ABSTRACT

Title of Document:	Sensor-Augmented Lightning Mitigation; Implications for Risk at Hydraulic Fracturing Storage Facilities
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Hydraulic Fracturing (hydro fracking) has revolutionized oil and gas production in the United States. Controversy has been widespread and plenty of uncertainty remains commonplace in the public. The topic of hazardous chemicals and pollution associated with hydro fracking will be presented in some detail. However, the key focus will be on sensors and lightning mitigation at produced hydrocarbon storage batteries. Unmitigated fires and explosions will be shown to cause $10 million per direct strike in some lightning risk zones. Lightning has stood as an unresolved threat to hydrocarbon storage facilities for over 100 years. Literature research has shown that 33% of all modern hydrocarbon tank accidents

are due to lightning (Chang and Lin, 2006); in addition, cloud-ground lightning strikes are predicted to increase by 50% this century (Romps et al., 2014). An overlay of the current National Lightning Detection Network (NLDN) risk map and the Energy Information Administration (EIA) shale play map clearly show the lightning threat only increasing with the migration of future shale activities. While planning may change, shale deposits and regional lightning threats are not changing geographically; this research quantifies the threat and outlines clear lightning mitigation strategies. Furthermore, real-time detection and the associated methodology of lightning mitigation have implications for industries far beyond hydro fracking. By leveraging industrial standards for Fire and Gas Systems (FGS) such as IEC 61511, the proposed lightning effects mitigation system has a pathway toward verification and eventual validation at a broad array of industrial sites. Some extended applications included Navy fuel storage depots and Liquefied Natural Gas (LNG) facilities.

SENSOR-AUGMENTED LIGHTNING MITIGATION; IMPLICATIONS FOR RISK AT HYDRAULIC FRACTURING STORAGE FACILITIES

By

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Chapter 1: Introduction

This Chapter begins with an overview of hydraulic fracturing (fracking) from the past to the present along with a review of key terms, risks associated with fracking and areas where fracking could benefit from operational optimization. A statement of the problem under investigation is presented followed by envisioned beneficiaries of the research. The Chapter concludes with a description of the organization of the entire document.

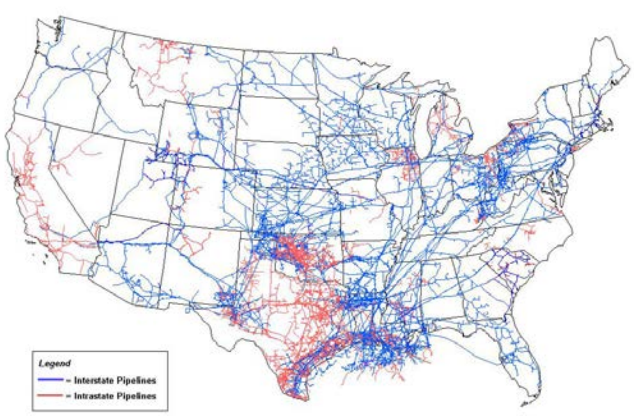
1.1 Background – Hydraulic Fracturing, Definitions, Risks, and Operational Optimization

In ancient times, lightning strikes would ignite underground seepages of natural gas. These self-sustaining fires of seemingly mystical origin mystified the ancient Greeks. On occasion this even resulted in the construction of temples housing priestess including the Oracle of Delphi whose prophetic powers were thought to originate from the flames (Speight, 2007).

Natural gas is, in many ways, the ideal fossil fuel. It is clean, easy to transport, and convenient to use. From an historical perspective, in 1821 William A. Hart drilled a 27 foot deep well in Fredonia, New York in an effort to get a larger flow of gas from a surface seepage of natural gas. This was the first well intentionally drilled to obtain natural gas (Victor et al., 2006; Speight, 2007). For most of the 1800s, natural gas was used almost exclusively as a fuel for lamps. Because there were no pipelines to bring gas into individual homes, most of the gas went to light city streets.

It took the construction of pipelines to bring natural gas to new markets. One of the first lengthy pipelines was built in 1891, it was in excess of 100 miles long and carried gas from fields in central Indiana to Chicago. This first pipeline did not initiate an immediate construction boom; rather, there were very few pipelines built until after World War II in the 1940s (Tussing and Barlow, 1984; Foss and Head, 2004).

Improvements in metals, welding techniques and pipe making during that war made pipeline construction more economically attractive. In addition, necessity due to costal tanker disruptions during World War II caused an uptick in large gas pipeline construction; Tennessee Gas Company built a 24 inch diameter, 1265 mile long natural gas line from the desert southwest to the East Coast (Kennedy, 1993). After World War II, the nation began building its pipeline network. Throughout the 1950s and 1960s, thousands of miles of pipeline were constructed throughout the United States. Today, the U.S. pipeline network, a map of which is presented as Fig. 1-1, if laid end-to-end, would stretch to the moon and back *twice* (Islam, 2014).



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Fig. 1-1. Natural gas pipelines within the US (source: Energy Information Administration) (2009).

Like oil production, some natural gas flows freely to wells because the natural pressure of the underground reservoir forces the gas through the reservoir rocks. These types of gas wells require only a "Christmas tree" – such as that shown in Fig. 1-2, or a series of pipes and valves on the surface, to control the flow of gas.

Fig. 1-2. Natural gas "Christmas Tree".

In 2015, only a small number of these free-flowing gas formations still exist in many U.S. gas fields. This implies that in the vast majority of gas extraction wells in the U.S., some type of pumping system is required to extract the gas present in underground formations.

Often, the flow of gas through a reservoir can be improved by creating tiny cracks in the rock, called "fractures," that serve as open pathways for the gas to flow. In a technique called "hydraulic fracturing," drillers force high pressure fluids (principally water) into the underground geological formation to crack the rock. A "propping agent", most commonly a very fine grain sand or even tiny glass beads, is added to the fluid to prop open the fractures when the pressure is decreased. A diagrammatic depiction of the process is presented as Fig. 1-3.

It is worth noting that the process of “treating” carbonate rock formations with acid for enhanced oil extraction, was first done in 1895 by the Standard Oil Company in Lima, Ohio (Kalfayan, 2007; 1895). Following this, a patent was issued to Herman Frasch in 1896 for the process (Dyke, 1896). In 1934 and 1933, Putnam et al. published papers describing the techniques and advancements for the acid treatment of oil wells (Putnam, 1933; Putnam and Fry, 1934). In the 1934 paper, Putnam outlined how over the previous 3 years, 3,000 “lime” oil wells were treated with acid resulting in an average production increase of 448% overall (Putnam and Fry, 1934). As a further advancement, the first recorded use of hydraulic fracturing – “fracking” – with a propping agent (a type of sand) was performed in the late 1940s (Kalfayan, 2007). The practice continued at a modest pace throughout the 1950s and 1960s with a significant expansion in volume productivity from unconventional (hydro fracked) wells in the late 1960s and 1970s as can be clearly interpreted from a 2010 paper by Nehring (NEHRING, 2010) . Fracking has been performed around the world, but became of substantially notoriety in the U.S. in the 2000’s when the companion technology of horizontal drilling allowed oil and natural gas extraction to radically improve in efficiency (Hill et al., 2012). This recent growth in the horizontal drill process has been profound; for example, in 2013 61% of U.S. wells drilled were horizontal as compared to 10% in 2004 (Hughes, 2013).

From the standpoint of a easy to understand definition, the fracking procedure itself can be defined as: "…the precise stimulation activity, limited to the fluid action in initiating and extending cracks in the rock" (King, 2012). Of course, the entire hydro fracking project is much more complicated as will be shown in the balance of this chapter; in fact, Fig. 1-3 begins to highlight some of the complexity involved.

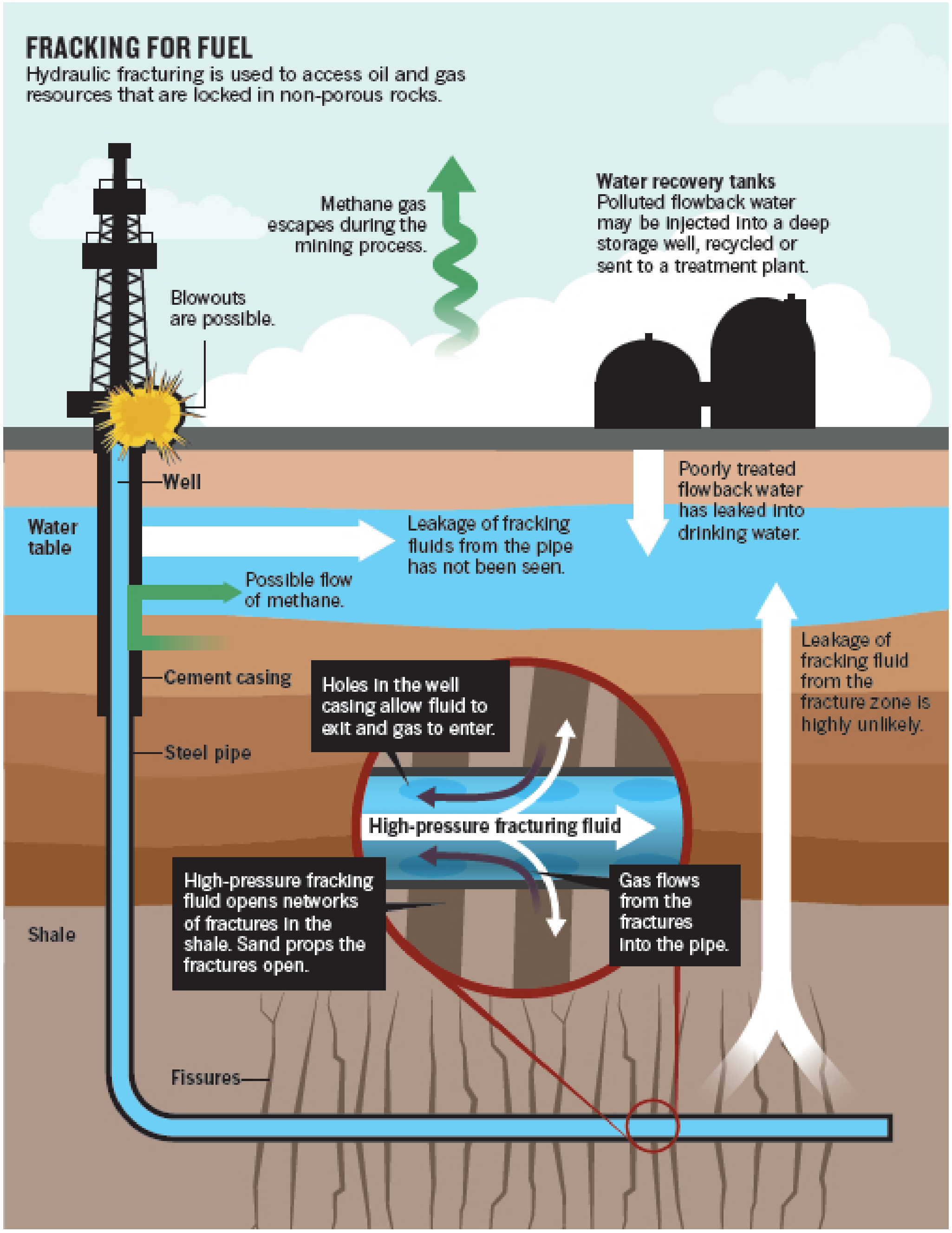


Fig. 1-3. Representation of a fractured "well" (Howarth et al., 2011a)

The growth pattern of natural gas as the fuel of choice is clearly described in (EIA, 2011) and its tradeoffs are debated in (Howarth et al., 2011a). As the U.S. Department of Energy (DOE) explains, domestic natural gas will grow to displace coal in the coming decades (EIA, 2011). Much more recently, the DOE also cited the relatively low cost of natural gas and the continued expectation for price reductions as a principal reason for its accelerated industrial use.

This industrial utilization feedback loop – increased use leading to increased demand leading to increased production leading to increased supply - is further driving the expansion of natural gas use. It is anticipated that by 2040, natural gas will overtake coal as the principal source of electricity generation in the United States (EIA, 2014). As previously mentioned, the increasing use of horizontal drilling coupled with fracking techniques has led to a recalculation of the world reserves of natural gas, as seen in Fig. 1-4.

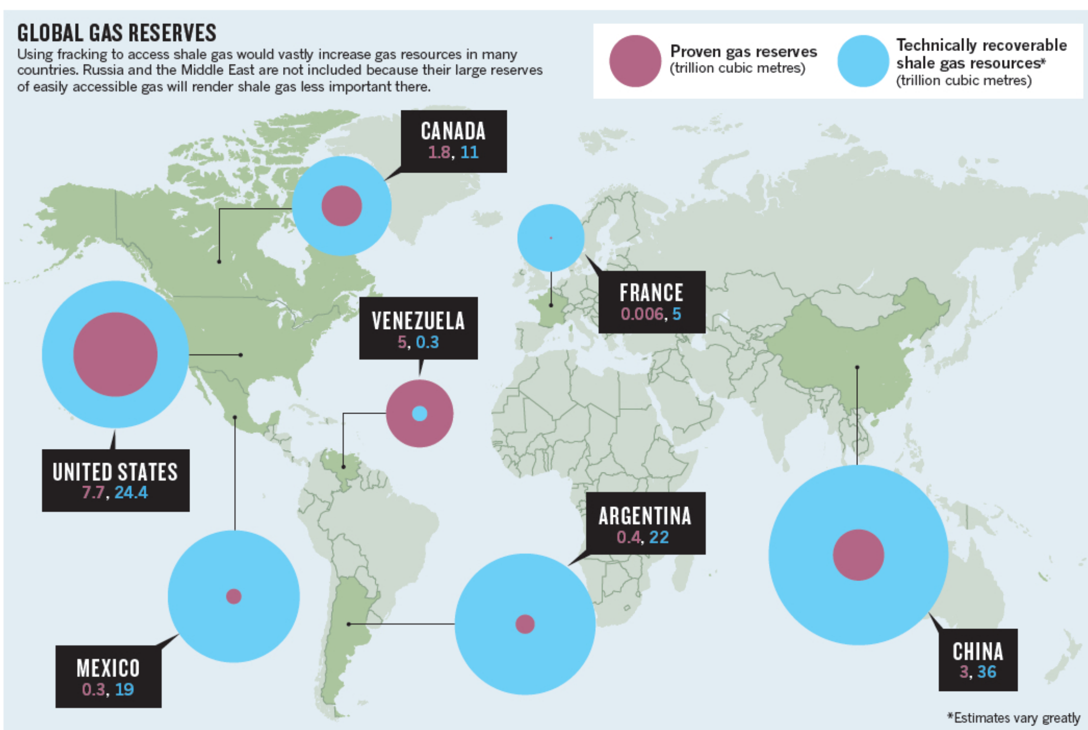


Fig. 1-4. World reserves of natural gas (Howarth et al., 2011a)

As previously stated, hydraulic fracturing (fracking) - also referred to as "hydro fracking" or "hydro-fracking" involves the stimulation of a drilled and completed well for the maximum extraction of underground resources including: natural gas, oil, and even geothermal energy. From a project management perspective, the end-to-end process associated with well preparation and fracking has numerous steps, including: injection fluid acquisition, well drilling and construction, stimulation and recovery, and environmentally compliant waste disposal (2010b).

The horizontal drilling process can have a dramatic increase on the production rates vs. conventional vertical drilling and production operations. For example, experts from a major fracking company indicate that "shale plays" (geological formations of shale rock where hydrocarbons reside) near Midland, TX have greatly benefited from the combination of horizontal drilling and hydro fracking technology with the production rate per well increasing by 5-15 times over a conventional well. In other words, conventional wells in the Midland, TX area would yield 100 bbl of crude per day with horizontal drilling alone, whereas hydro fracking and horizontal operations can result in wells that produce 1500 bbl per day. --The economic implications of such an increase are obvious.

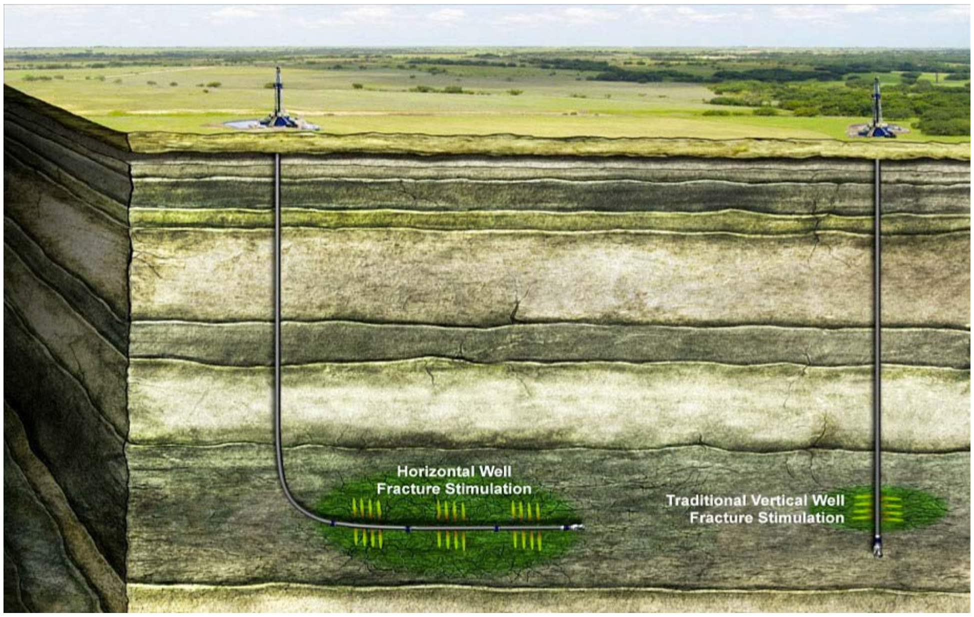


Fig. 1-5. Depiction of horizontal and vertical fracked wells (Murchison Oil & Gas, 2010).

Fig. 1-5 illustrates how horizontal wells have a larger stimulation volume than vertical wells. Since shale plays are in layers, horizontal wells can follow the pay region more efficiently than vertical wells. To increase production even more, drilling locations – referred to as “pads” - often have 3 or more wells to minimize logistics per well and setup communication between wells during fracking. Geological oil/gas reservoir engineers sometimes referring to “well communications” in the context that within the geological formation, fracking at one well site may influence production and extraction from neighboring wells. Such well communication results in localized fracturing of the shale play region between wells, and thus producing even large production than single non-communicating wells[1].

[1] Wells in communication are in close proximity as to influence the production of adjacent wells

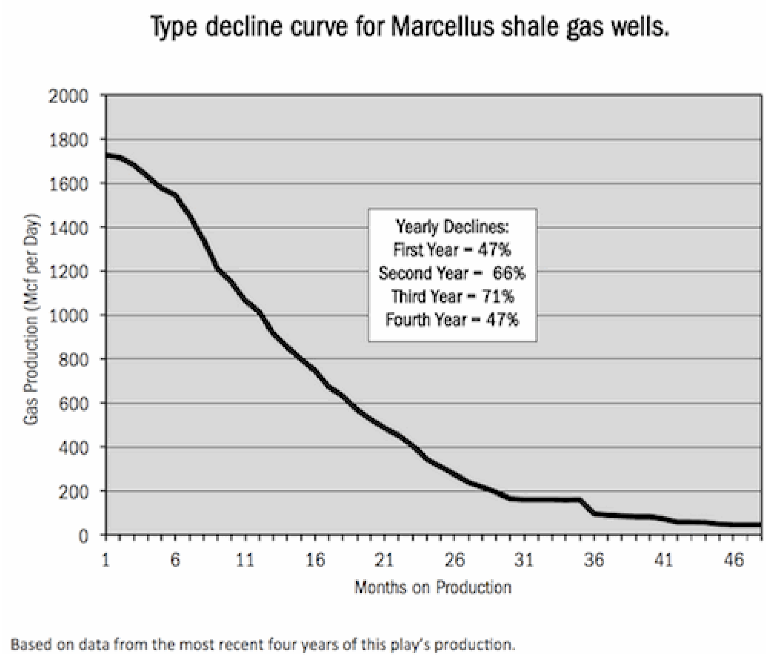


Fig. 1-6. Decline curve for Marcellus shale gas wells

Naturally, a well's production rate does not remain constant for its entire life, from a mathematical prospective, fracked wells can follow a pattern of exponential decay

$$Well\ production\ over\ time = e^{-Qx}$$

Eq. 1-1. Exponential decay well production curve (Hill et al., 2012)

In Eq. 1, Q is a scalar and determines the overall production decay characteristics of a fracked well. Several examples are shown in Fig. 1-7.

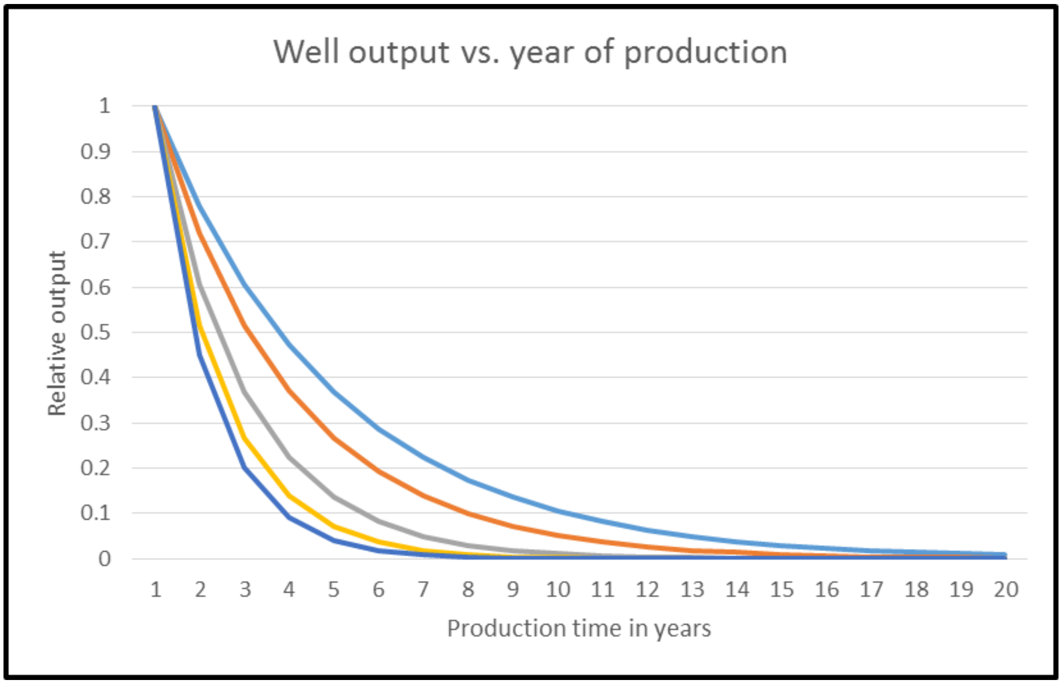


Fig. 1-7. Fracked well production over time (plots of Eq. 1-1)

In addition to these natural log decay functions shown in Fig. 1-7, exploration and production companies (E&P companies) also use harmonic and hyperbolic curves. The choice in curve is supported by regional geology, and experience with adjacent wells (Lee and Wattenbarger, 1996).

Some of the most common decline curve trend functions are outlined in Petroleum Production Systems by Hill et al. (Hill et al., 2012) are shown in Table 1-1.

Curve Type	Exponential	Harmonic	Hyperbolic
Instantaneous production rate at time t	$q(t) = q_i e^{-at}$	$q(t) = \frac{q_i}{1 + a_i t}$	$q(t) = \frac{q_i}{(1 + \frac{a_i t}{n})^n}$

Table 1-1. Common decline curve trend functions (Hill et al., 2012)

The Estimated Ultimate Recovery (EUR) provides a fair benchmark for recoverable resources while providing insight into what the marginal cost might be for extended recovery. However as an Energy Information Administration (EIA) report indicates (2012), these estimates are highly variable and differ from well to well and don’t include the impacts of new technologies **(such as sensors)** being adopted. With all this said, it is easy to see that a fracked well provides the vast majority of their payback in the 0-2 year range--- this is truly where money can be made or lost. In particular, an end-to-end exploration and production company must consider models such as Net Present Value (NPV) to determine the value of a particular well.

1.1.1 Operational Optimization

Before we present NPV in relation to the fracking arena, another term to consider is Energy Return on Energy Invested (ERoEI). In simple terms, this is the total amount of energy required to produce a unit of recoverable hydrocarbons. Guilford et al. has done an exhaustive study of ERoEI for U.S. oil and gas; In their paper (Guilford et al., 2011), a total of 13 point estimates for ERoEI were taken over a 90 year period. The authors proceed to discuss a simple Eq. and my research efforts have built upon their Eq. to be more inclusive of sensors.

$$ERoI = \frac{Mean\ quantity\ of\ energy\ recovered\ from\ production\ activities}{Quatity\ of\ energy\ for\ activity\ lifecycle}$$

Eq. 1-2. ERoI (Guilford et al., 2011)

Within this dissertation, the approach is taken that energy and cost are fungible concepts. In particular, a unit of energy can easily be calculated in terms of currency or USD. So, it follows that ERoI can be transformed into USD values by using the daily traded market value for energy commodities such as WTI (West Texas Intermediate) crude and Natural Gas. If we simply transform energy saved into terms of money saved we can then see the connection between Eq. 1-1 and 1-2.

This research project now introduces the novel concept of SARoI (Sensor Augmented Return on Investment). By building upon the research of Guilford et al., how does the introduction of sensors into fracking operations impact the potential for financial savings? In the following Eq., the concept of Sensor Augmented Return on Investment (SARoI) is introduced. SARoI parallels ERoI, but the benefit of a sensor is calculated in terms of currency rather than energy saved.

$$SARoI = \frac{Sensor\ Augmented\ Value\ Added}{CAPEX + Maintenance + Integration + Training}$$

Eq. 1-4. Sensor Augmented Return on Investment

$$NPV = \sum_{t=1}^{n} \frac{S_t}{(1 + i_d)^t} - I_o$$

Eq. 1-5. Net Present Value (Mian, 2011)

S_t = (gross revenue – LOE – taxes) at the end of year t

I_0 = initial investment outlay at t=0

i_d = the discount rate; required minimal rate of return

n = the practical economic life of the well project

In Eq. 1-5., M.A. Mian presents the concept of Net Present Value (NPV) in relation to a resource in the petroleum industry (Mian, 2011). We now take Eq. 1-5 and modify it for the production profile of a hydro fracked well as follows. The contribution of sensors to the NPV of a hydro fracked well project is clearly shown in Eq. 1-6 by the integration of Eq. 2 and 5.

$$NPV = \sum_{t=1}^{n} \frac{(e^{-Qt}) - LOE - taxes + SARoI}{(1 + i_d)^t} - I_o$$

Eq. 1-6. Sensors contribute to the NPV of a hydro fracking project.

In Eq. 1-6, a production profile of e^{-x} is assumed; however, as was discussed in relation to Fig. 1-9, harmonic and hyperbolic profile curves can also be used (Lee and Wattenbarger, 1996).

1.1.2 Fracking Operations

As shown in Fig. 1-8, hydro fracking operations can be broken down into 3 separate operational domains. The intersection – and a key element of this dissertation's research – of transportation and surface operations is the "product storage" shown in Fig. 1-8.

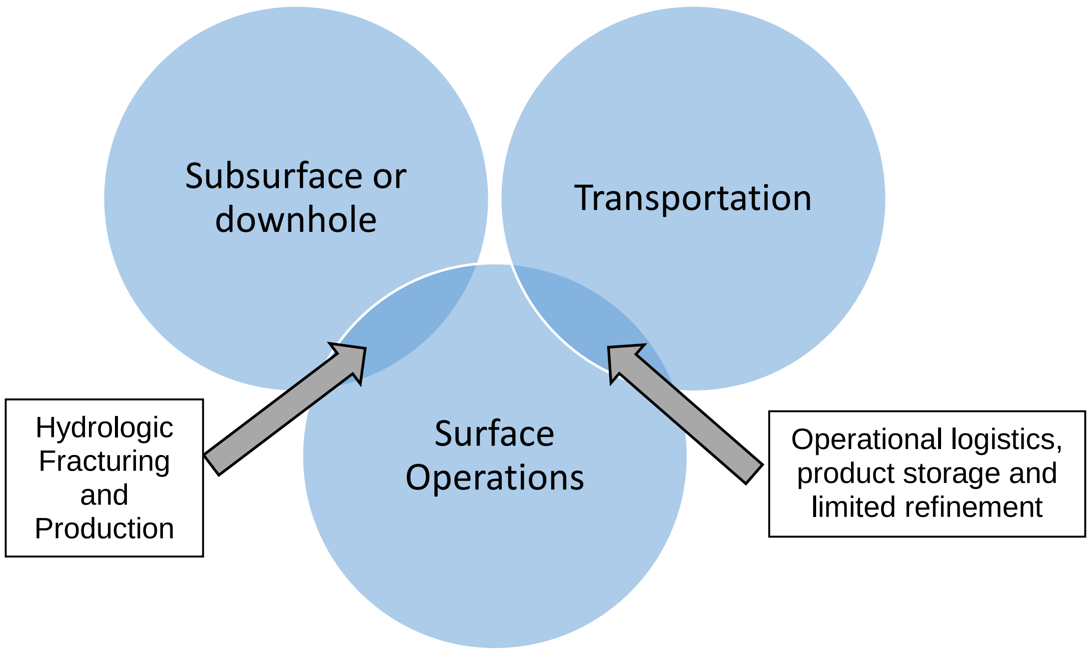


Fig. 1-8: Hydraulic Fracturing Project Anatomy

The transportation operational area of Fig. 1-9 principally deals with the transportation of materials and supplies for hydro fracking operations including: sand, water, chemicals, big iron, equipment / machinery, waste water, solid garbage, produced oil, and produced gas.

The only portion of transportation that was examined in this dissertation was the transportation and storage of produced gas and oil at the battery[2] facility; the in-field experiments conducted for this research observed a distributed star-network topology for feed pipelines from operational fracking wells to a centralized storage battery. Pipes were run on the surface – versus being buried – from the well pads to

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[2] The battery is an onsite storage and rudimentary purification facility for produced liquid hydrocarbons. In our case, storage tanks are fiberglass.

the battery where limited chemical separation occurred, and the resultant separated constituents pumped into separate storage tanks.

While the subsurface – or downhole – operations and the general surface operations (such as sand truck placement and unloading) are not central to this research, Fig. 1-9 depicts how surface operations, transportation, intersect and impact storage. Individuals interested in finding out more information on these two topics should consult (Holloway and Rudd).

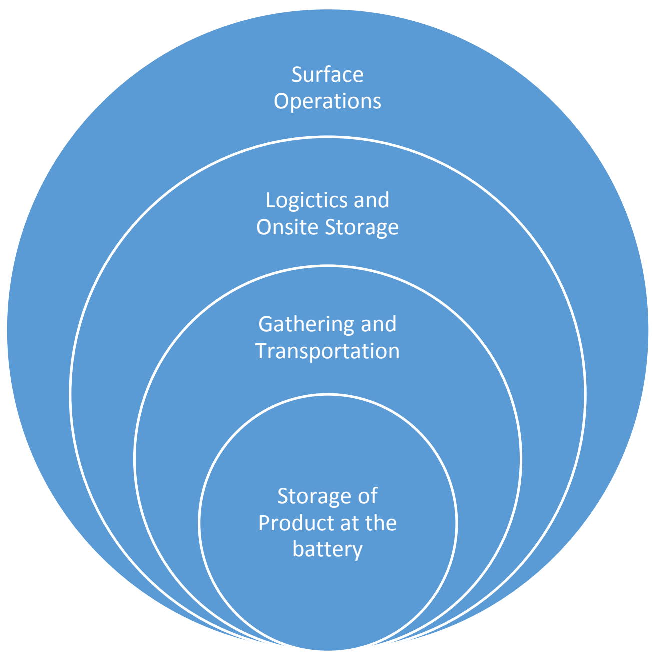

Fig. 1-9. Components of Surface Operations

Logistics at hydro fracking sites could be greatly improved with better sensors and integrated management systems. Currently large hydro fracking companies have no master historian working in collaboration with an overall project management system that is able to ingest live field information from sensors. Robust and purpose built sensors deployed at the operational edge are key for a more efficient view on operational risk.

Fracking is not a monolithic process that is invariable through time; rather, fracking pads house a large collection of hardware that is moved on and off site as required. Some of this equipment includes pumps, hose fittings, tools, drill bits and pipe. Tracking the location and inventory of these items is currently done only by inspection and is not automated (based on discussions with onsite engineering supervisors). While individual companies may have a large number of fracking sites in a relatively small geographical area, the sheer volume of wells, such as these shown in the photograph of Fig. 1-10 – which this researcher took while flying over west Texas immediately shows the potential logistics and informatics difficulties for sub-optimally managed projects.

Fig. 1-10. West Texas fracking sites – Rooke 2014

Transportation of sand, water, chemicals, and other supplies to and from fracking sites lack an integrated project management system. Often during fracking operations, sand trucks are lined up in a queue waiting to be unloaded at a cost of $150 per hour for the driver alone; see Fig. 1-11. Truck and unload sensors could easily be placed onsite and integrated with real-time traffic from public sources like Google Traffic to more efficiently schedule trucks.

Fig. 1-12. Photograph of fracking sand trucks being unloaded – Rooke 2014

Gathering pipes, shown in Fig. 1-12, transport all liquid products to the battery. The mixture of fluids transported within the gathering pipes includes waste water, crude oil and other hydrocarbons.

Fig. 1-12. Gathering pipes lead to the Battery (photograph taken by author).

The battery is where it all comes together. The fluid mixture coming from the fracked wells - typically between 6-8 well pads (with each pad containing 3 or more producing wells) - is gathered at the battery. Product from each well is transported by polyethylene pipes which are for the most part simply ran on the surface as shown in Fig. 1-12. Very limited chemical separation is performed at the battery where the produced petroleum is stored in the fiberglass tanks of Fig. 1-13. With that said, the produced hydrocarbons are not of sufficient quality for immediate distribution, and undergo crude separation of heavy hydrocarbons and even sulfur containing gases such as hydrogen sulfide at the battery (Howarth et al., 2011b).

Fig. 1-13: The battery (photograph taken by author).

1.1.3 The fracking process in detail

The process of fracking itself takes place below ground and is beyond the scope of this research project. Underground, the complex world of geology enters into the picture; and with that, so do additional complications. However, sensors are used underground mostly notably pressure, temperature, and vibration sensors. Often, these sensors use fiber optics as both the sensor and the communications path (Hill and Meltz, 1997).

The “downhole” arena of fracking has been heavily researched; this is where the shale deposits reside; and thus, hydrocarbons including: methane, ethane, and butane. Also, crude oil is produce, which in some case is the principal object for the fracking operation. Of course, this is dependent on geology, and in some Texas plays, crude oil amounts to 70% of the revenue per well.

Form a percentage perspective, fracking fluid is principally composed of sand (silica) and water. There are also other components including guar gum, antifungal agents, surfactants, and anticorrosion agents; for a complete list of Halliburton chemicals used and their calculated concentration review a paper written by Rooke et al. in 2011 (Rooke and Fuhr, 2011) from which Table 1-1 was extracted.

Fracking Fluid Component Product Name	Median Overall Concentration of Component in Fracking Fluid	Purpose	Chemical	ACGIH TLV-TWA (Exposure Safty)	OSHA PEL-TWA (Exposure Safty)	Portion of Component (Median value taken)	Concentration of Chemical in Overall Fracking Fluid (Parts per Million)
CAT®-3	0.1000%	Breaker Catalyst	EDTA/Copper chelate		1 mg/m3	20.0%	2.0
CAT®-4	0.0055%	Breaker Catalyst	Diethylenetriamine	1 ppm (S)		45.0%	0.2
CL-23™	0.0600%	Crosslink Agent	Zirconium, acetate lactate oxo ammonium complexes	5 mg/m3		45.0%	2.7
CL-23™	0.0600%	Crosslink Agent	Ammonium chloride	10 mg/m3	10 mg/m3	14.0%	0.8
CL-37™	0.0325%	Crosslink Agent	Triethanolamine zirconate	5 mg/m3	5 mg/m3	80.0%	2.6
CL-37™	0.0325%	Crosslink Agent	Propanol	100 ppm	200 ppm	20.0%	0.7
CL-37™	0.0325%	Crosslink Agent	Glycerine	10 mg/m3	15 mg/m3	20.0%	0.7
FR-66™	0.0600%	Friction Reducer	Hydrotreated light petroleum distillate	200 mg/m3		20.0%	1.2
LoSurf-300D™	0.1750%	Surfactant	Heavy aromatic petroleum naphtha	5 mg/m3	5 mg/m3	20.0%	3.5
LoSurf-300D™	0.1750%	Surfactant	Naphthalene	10 ppm	10 ppm	3.0%	0.5
LoSurf-300D™	0.1750%	Surfactant	1,2,4 Trimethylbenzene	25 ppm		0.5%	0.1
LoSurf-300D™	0.1750%	Surfactant	Poly(oxy-1,2-ethanediyl), alpha-(4-nonylphenyl)-omega-hydroxy-, branched	Not listed but likely toxic	Not listed but likely toxic	2.5%	0.4
HAI-404M™	1.5000%	Corrosion Inhibitor	1-(Benzyl)quinolinium chloride	Not listed but likely toxic	Not listed but likely toxic	7.5%	11.3
BE-6™	0.0018%	Biocide	2-Bromo-2-nitro-1,3-propanediol	Not listed but likely toxic	Not listed but likely toxic	80.0%	0.1
LGC-36UC™	0.4250%	Liquid Gel Concentrate	Naphtha, hydrotreated heavy	Not listed might be toxic	Not listed might be toxic	45.0%	19.1
BE-9™	0.0750%	Biocide	Tributyl tetradecyl phosphonium chloride	Not listed, No evidence of Mutagenicity not considered a Carcinogen	Not Listed, No evidence of Mutagenicity not considered a Carcinogen	7.5%	0.6
BE-3S™	0.0150%	Biocide	2-Monobromo-3-nitrilopropionamide	Likely non toxic	Likely non toxic	3.0%	0.05
BE-3S™	0.0150%	Biocide	2,2 Dibromo-3-nitrilopropionamide	Dow Chemical company	Dow Chemical company	80.0%	1.2

Table 1-1: Calculated concentration of chemicals in fracking fluid; Rooke et al. (Rooke and Fuhr, 2011).

While the technologies and (many) procedures associated with fracking have just been presented, it is worthwhile to take a step-by-step review of the entire hydraulic fracturing procedure.

Well initiation:

Companies start the drilling process on typically a 3-acre pad of land, which provides space for the many trucks that become part of an oil and gas drilling process. The process begins with vertical drilling. A drilling rig is brought on site to drill the well, which will go to depths of up to 10,000 feet below the surface. This process can take from a week to 10 days, depending on the site's operation and subsurface geology. Drilling stops initially below the water table so that the well can be encased in cement to prevent anything from the well leaking into the water table. Once the casing is completed, a 7-inch drill bit will drill more than a mile to get to the leased formation in which to frack or in certain cases, such as the Niobrara or Codell formations, stacked hydrocarbon-laced formations beneath several impermeable rock formations. Once the drill bit hits bottom, or the "pay zone," the company will drill what is called the "bend," which is the curve the well takes to get into the horizontal portion of the zone. The bend alone could take up to two days to drill. Throughout the drilling process, drilling mud is pumped in to cool the drill bit and act as a means for the resulting debris to leave the well (Dunn, 2014).

The horizontal portion of the well is then drilled for an additional 4,000 to 10,000 feet, then encased in cement, with a 4-inch metal pipe in the center to allow for the oil and gas to flow to the surface. At this point, the well is just a hole drilled into the ground, with a cement barrier between the pipe, the formations and water table. With the drilling completed, the drilling rig is packed up and activity stops until the actual fracking begins. The time between drilling being completed and fracking beginning typically ranges from days to weeks (Dunn, 2014).

Focusing on the frack:

The actual fracking process uses a considerable amount of machinery capable of driving the fluid down more than a mile, coupled with calculations of the exact mixtures of chemicals and water and sand (see Fig. 1-16) and the pressure it takes to crack tiny little fissures into rocks, more than a mile beneath the surface. Fine grain sand transported to the well site via trucks along with large amounts of water and chemical additives are pumped into the well at high pressures, so as to crack the rock in different stages in the horizontal (parallel to the surface) portion of the well (Dunn, 2014).

Conversations between the author and on-site fracking engineers: “To open fractures at bottom-hole pressures in the Eagle Ford, Niobrara, and the Permian Basin you probably need downhole pressures of 10,000 psi or so to open the rocks”. The chemicals do not erode the rock to create the cracks or fracs — it’s the high pressure of the water that opens them up. The chemicals, such as guar gum are added to help the water to gel, allowing the sand an easier vehicle in which to move. (again from the conversation:) “When it’s thicker, it does a better job of carrying sand downhole, if you think about a handful of sand at a lake, and you put it in water, the sand will settle quickly to the bottom of the lake. We don’t want that to happen in factures.” (Dunn, 2014)

Those cracks, now held open by the fine grain sand, release the trapped oil and gas inside, which flow back to the surface after the downward pressure from fluids is released from the well. Soap ingredients are frequently added to the gel to prevent bacterial growth in the well, reducing the probability of bacterial-released gases.

The Layout:

The sand, water, chemicals and production that comes out of the well during the fracking of the well - commonly called flowback – plus injection of the fracking fluid into the well, requires numerous trucks to carry the water, the sand, and the chemicals to mix them all together, and more truck horsepower to combine it all to shoot down through a pipe into an 8-inch hole in the ground are used. To prep the area, several 500-barrel tanks for water storage or a massive, 40,000-barrel pool to store water – preinjection and flowback- is erected on the periphery of the site. Sand storage tanks arrive, then are filled. A typical frac job will utilize from 1.5 million to 6 million pounds of sand. Due to all of the top-side machinery and processes involved, traditional (non) sensor-augmented project management methodologies are far from optimal.

(again, continuing the conversation:) "When the rest of the crew arrives on location, they'll typically rig up to the well head with a missile." The missile is a manifold around which most of the activity centers, to ultimately pump fracking fluid downhole. Crews will line on each side of the missile five to six semi-trucks, which contain the horsepower to create enough pressure to pump the fluid downhole at the proper rate.

In addition to the horsepower trucks, there are sand trucks and trucks containing the chemical additives to thicken the water to keep the sand moving in the well. A hydration truck, through which the chemicals are added to the water to "gel," and a blender, which mixes that fluid with the sand, are nearby. All surround the missile in a horseshoe shape. "The blender sends the mixture of sand water to the low-pressure side of the missile. From that missile, we have 10-12 connections to the individual horsepower units, which really pressurize the mixture of sand and fluids so the (missile) can send it (through its high-pressure side) downhole at pressures that can crack the rock open."

That one process is good for one frack, or stage, at which the horizontal well is cracked from being hit at such high pressures. A typical well can have 20 fracks, each necessitating this procedure of blending, pressurizing and cracking. A typical frack job can last up to 20 hours — one frack stage per hour — from start to finish. At the open end, or the top of the horseshoe, is a data center, or a trailer containing about five to six people controlling the science of the job. There's usually a representative or two from the oil and gas company, a frack job supervisor and an engineer. On jobs where crews utilize a large pool of water, the water is usually being heated to temperatures of about 70 degrees to provide the perfect chemical combination with the additives and sand. At some point in the drilling and completion process, crews will build oil and gas storage tanks, vapor recovery units to control air emissions, and oil and gas separators for the eventual well production. All will be strategically located around the wellhead.

Completion:

Once all the fracks are created, the downward pressure is removed from the well. Within a couple of days, the release of that pressure will reverse, allowing the oil and gas to flow from the rocks and up the well. (from the conversation;) "At end of the frac job, the flow stream is reversed. Instead of pumping things downhole, due to the pressure we created, we have almost no pressure at the surface, then the flow reverts and oil and gas and some of the water find their way back from downhole to the surface." All the equipment is removed from the site, leaving only the wellhead, the storage tanks, separators and emissions control. Production can last for years.

Unrefined produce hydrocarbons are gathered from 6 or more well heads and transported in 3-inch polyethylene gathering pipes to a local battery facility (see Fig. 1-13). These hydrocarbons are stored in the battery which was briefly discussed in section 1.1.2, and will be covered in detail throughout this dissertation.

1.1.4 Risk of lightning

The mixture of chemicals present in a storage battery pose a threat to the environment – if spilled, etc – as well as a financial risk to the fracking company, again if spilled, etc. A particular risk to both the environment and the fracking company arises if the storage tank explodes and/or catches on fire (Argyropoulos et al., 2012). Such situations have occurred numerous times due to lightning strikes (Chang and Lin, 2006), such a burning storage battery fire is shown in Fig. 1-15.

(a) (b)

Fig. 1-14. Fracking batteries on fire (a) Texas, (b) North Dakota. Both fires were caused by lightning strikes.

As a fact of nature, lightning strikes are difficult to avoid, and are by far the primary cause of catastrophic storage tank incidents (Chang and Lin, 2006). Chapter 3 of this dissertation will highlight how others have made efforts to ground tanks with limited success and even counterproductive results. This situation might have been substantially lessened if instrumentation could have sensed the increase in the electric field and static charge increasing on the storage tanks, relayed that information to a control system which could adjust the ratios of the constituent fluids in each tank thereby lessening the probability of a fire if struck by lightning. --**This** forms the essence of the dissertation's research question. It is also immediately apparent that the organizations and individuals who would benefit from the research question "answer" are: us, the environment and the fracking company.

1.2 Statement of the Problem Under Investigation

Large scale hydraulic fracturing sites with inherent exposure to potentially catastrophic events such as lightning, lack sensor integration with decision algorithms. Many parameters at a fracking site are observed by an operator and action is taken manually. After discussions with engineers of numerous fracking company owner-operators including Pioneer Natural Resources (PXD), Exxon, and Halliburton, it quickly became apparent that a lack of trust and actualization is preventing change. Scholarly studies have shown that the decision of operators to trust automated controls is dependent on their general trust in automation and their own self-confidence (Bisantz and Seong, 2001). In particular, senior and often more risk adverse engineers have an attitude of "if it ain't broke, don't fix it". Control systems including Supervisory Control and Data Acquisition (SCADA) systems operate under the premises of maximum availability with limited features. Operators in the industrial controls arena are highly risk adverse, and thus do not embrace change. However, tradition must change as sensors with automatous decision algorithms are introduced into industry.

The problem being addressed by this thesis involves the integration of customized electric field sensors and communications to allow for the measurement of static field increases on fiberglass tanks used in hydraulic fracturing storage batteries. The instrumentation must be correctly deployed with local communications – to allow an on-battery control system to adjust the constituent chemicals in the storage tanks to reduce the combustibility of the fuel being stored (for the ignition source, lightning, and the oxygen present (the storage tanks are in the field) cannot be controlled) – per Fig. 1-16's Explosion Triangle – but thereby reduce the risk associated with a lightning-induced fire at a fracking site storage battery.

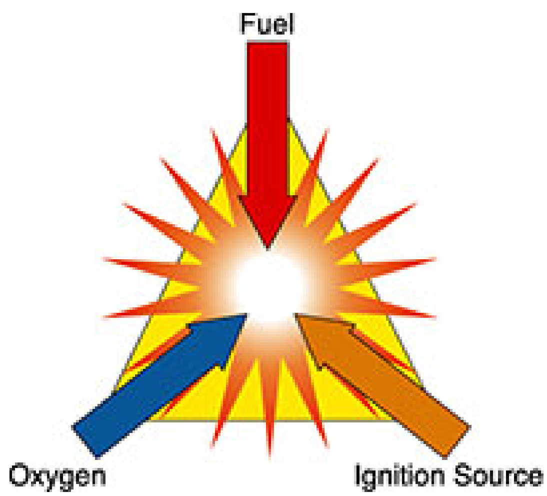

Fig. 1-15. The Explosion Triangle.

While the specific use of this dissertation's research is immediate (and obvious), the more general point is the integration of a sensor-based automated operations management systems to reduce risk. Once proven in this specific example, the concept may be expanded to other areas of applicability.

1.3 Beneficiaries of this Research

Hydro fracking operations will be the immediate beneficiaries of this research. In addition there will be broader implications associated with this sensor-based automated mitigation and protection systems. Benefits to the fracking industry will include lower operational risk cost through better detection of lightning and higher profits through less unnecessary downtime due to lightning strikes.

1.4 Organization of the Document

This dissertation is comprised of 6 Chapters. Chapter 1 presented an overview of fracking and an initial description of the research problem. Chapter 2 presents a more thorough “deep dive” into the importance of the research problem and the potential impact of being able to obtain an answer to the research questions associated with the project. Chapter 3 is a review of the pertinent literature and prior efforts. The approach and methodology used in the pursuit of an answer to the research question is presented in Chapter 4. The research findings are presented in Chapter 5 followed by a Summary and suggestions for further research in Chapter 6.

Chapter 2: Description of the Research Questions Addressed

This chapter begins with an extensive review of the safety of hydraulic fracturing storage facilities. The research questions alluded to in Chapter 1 are more fully explained in section 2.2. Implications of "an answer" to these questions are presented and the chapter concludes with a summary.

2.1 The Safety of Hydraulic Fracturing Storage Facilities

The primary topic of this dissertation's research involves the risks and safety of the storage facilities – the batteries – associated with hydraulic fracturing and the application of sensor technologies for improved operation and safety. It is worthwhile to review the wider scope of hazards associated – correctly or incorrectly attributed to drilling, fracking, producing wells for particularly in the case of the fracking fluids, the chemicals will to varying amounts be present in the batteries. As this is important in light of accidents associated with storage facilities.

2.1.1 Risks & Hazards of the fracking process

The process of fracturing a well is far from benign. The following sections provide an overview of some of the issues and impacts related to this well stimulation technique. Fig. 2-1 provides a window into the massive scale of a hydro fracking operation. Here a well has been completed and capped and is ready for production. At this stage, the well is filled with a column of drilling mud to holdback the massive internal pressures imparted upon the fracked oil and gas deposit. During the production phase, of this well, the mud will be removed as oil and gas enter the well and extrude the drilling mud upward.

Fig. 2-1. Fracking pad with well head

Water Use:

In 2010, the U.S. Environmental Protection Agency estimated that 70 to 140 billion gallons of water are used to fracture 35,000 wells in the United States each year. This equals the approximate annual water consumption of 40 to 80 cities each with a population of 50,000. Fracture treatments in coalbed methane wells use from 50,000 to 350,000 gallons of water per well, while deeper horizontal shale wells can use anywhere from 2,000,000 to 10,000,000 gallons of water to fracture a single well. The extraction of so much water for fracking has raised concerns about the ecological impacts to aquatic resources, as well as dewatering of drinking water aquifers. It has been estimated that the transportation of two to five million gallons of water (fresh or waste water) requires 1,400 truck trips averaging a distance of 35 miles. Thus, not only does water used for hydraulic fracturing deplete fresh water supplies and impact aquatic habitat, the transportation of so much water also creates localized air quality, safety and road repair issues (Rahm, 2011), (Nicot and Scanlon, 2012).

Sand and Proppants:

Conventional oil and gas wells use, on average, 300,000 pounds of proppant, coalbed fracture treatments use anywhere from 75,000 to 320,000 pounds of proppant and shale gas wells can use more than 4,000,000 pounds of proppant per well. Frac sand mines are springing up across the country, from Wisconsin to Texas, bringing with them their own set of impacts. Mining sand for proppant use generates its own range of impacts, including water consumption and air emissions, as well as potential health problems related to crystalline silica (Pearson, 2013), (Smathers, 2011).

Chemicals:

In addition to large volumes of water, a variety of chemicals are used in hydraulic fracturing fluids. The oil and gas industry and trade groups are quick to point out that chemicals typically make up just 0.5 and 2.0% of the total volume of the fracturing fluid. When millions of gallons of water are being used, however, the amount of chemicals per fracking operation is very large. For example, a four million gallon fracturing operation would use from 80 to 330 tons of chemicals (Sawyer, 2009)

As part of New York State's Draft Supplemental Generic Environmental Impact Statement (SGEIS) related to Horizontal Drilling and High-Volume Hydraulic Fracturing in the Marcellus Shale, the Department of Environmental Conservation complied a list of chemicals and additives used during hydraulic fracturing. The table below provides examples of various types of hydraulic fracturing additives proposed for use in New York.

ADDITIVE TYPE	**DISCRIPTION OF PURPOSE**	**EXAMPLES OF CHEMICALS**
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2-Bromo-2-nitro-1,2-propanediol
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride) [Potassium chloride]

Corrosion Inhibitor	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Oxygen Scavengers
Crosslinker	The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	borate salts, Sodium acrylate-acrylamide copolymer
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillate
Iron Control	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol; polyacrylate
Solvent	Additive which is soluble in oil, water & acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons, methanol, isopropanol
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	ethoxylated alcohol

Table 2-1. Fracking chemicals proposed for fracking in New York State (Earthworks).

Many fracturing fluid chemicals are known to be toxic to humans and wildlife, and several are known to cause cancer. Potentially toxic substances include petroleum distillates such as kerosene and diesel fuel (which contain benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals); polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide.

Very small quantities of some fracking chemicals are capable of contaminating millions of gallons of water. According to the Environmental Working Group, petroleum-based products known as petroleum distillates such as kerosene

(also known as hydrotreated light distillates, mineral spirits, and a petroleum distillate blends) are likely to contain benzene, a known human carcinogen that is toxic in water at levels greater than five parts per billion (or 0.005 parts per million).
Other chemicals, used in fracking such as 1,2-Dichloroethane, are volatile organic compounds (VOCs). Volatile organic constituents have been shown to be present in fracturing fluid flowback wastes at levels that exceed drinking water standards. For example, testing of flowback samples from Texas have revealed concentrations of 1,2-Dichloroethane (DCA) at 1,580 ppb, which is more than 316 times EPA's Maximum Contaminant Level for 1,2-Dichloroethane in drinking water. VOCs not only pose a health concern while in the water, the volatile nature of the constituents means that they can also easily enter the air. According to researchers at the University of Pittsburgh's Center for Healthy Environments and Communities, organic compounds brought to the surface in the fracturing flowback or produced water often go into open impoundments (frac ponds), where the volatile organic chemicals can offgas into the air.

When companies have an excess of unused hydraulic fracturing fluids, they either use them at another job or dispose of them. These same fluids (in diluted form) are allowed to be injected directly into or adjacent to USDWs[3] (Underground Source of Drinking Water). Under the Safe Drinking Water Act (SWDA), hazardous wastes may not be injected into USDWs (EPA, 2012). Moreover, even if hazardous wastes are decharacterized (for example, diluted with water so that they are rendered non-hazardous), wastes must still be injected into a formation that is below

[3] A USDW is any aquifer which contains less than 10,000 mg/l total dissolved solids and is currently being used as a drinking water source or is of adequate quantity and quality for public consumption in the future

the USDW. Clearly, some hydraulic fracturing fluids contain chemicals deemed to be "hazardous wastes." To accommodate for this risk, the EPA has developed injection well Class categories with stringent guidelines (EPA, 2012) . In particular Class I owner-operators must demonstrate the financial capability to complete and plug the well (Tsang et al., 2002). On the other extreme, Class V owner-operators have the least oversight provided they adhere to the Safe Drinking Water Act (SDWA) (EPA, 2013).

Class of disposal well	Application and Description
Class I	Injection of municipal or industrial waste (including hazardous waste) below the deepest USDW.
Class II	Injection related to oil and gas production, including enhanced hydrocarbon recovery and hydrocarbon storage.
Class III	Injection of fluids for the extraction of minerals.
Class IV	Injection of hazardous or radioactive waste into or above a USDW (banned by regulation and statutes).
Class V	All other wells used for injection of fluids. These are generally shallow wells used to inject nonhazardous fluids into or above a USDW.

Table 2-2. EPA injection well classifications (Tsang et al., 2002).

Health Concerns:

Human exposure to fracking chemicals can occur by ingesting chemicals that have spilled and entered drinking water sources, through direct skin contact with the chemicals or wastes (e.g., by workers, spill responders or health care professionals), or by breathing in vapors from flowback wastes stored in pits or tanks.

In 2011, Colborn et al. published a paper entitled "Natural Gas Operations from a Public Health Perspective" (Colborn et al., 2011). In this paper, they summarized health effect information for 353 chemicals used to drill and fracture natural gas wells in the United States. Health effects were broken into 12 categories: skin, eye and sensory organ, respiratory, gastrointestinal and liver, brain and nervous system, immune, kidney, cardiovascular and blood, cancer, mutagenic, endocrine disruption, other, and ecological effects. The chart below illustrates the possible health effects associated with the 353 natural gas-related chemicals for which Colborn and her co-authors were able to gather health-effects data.

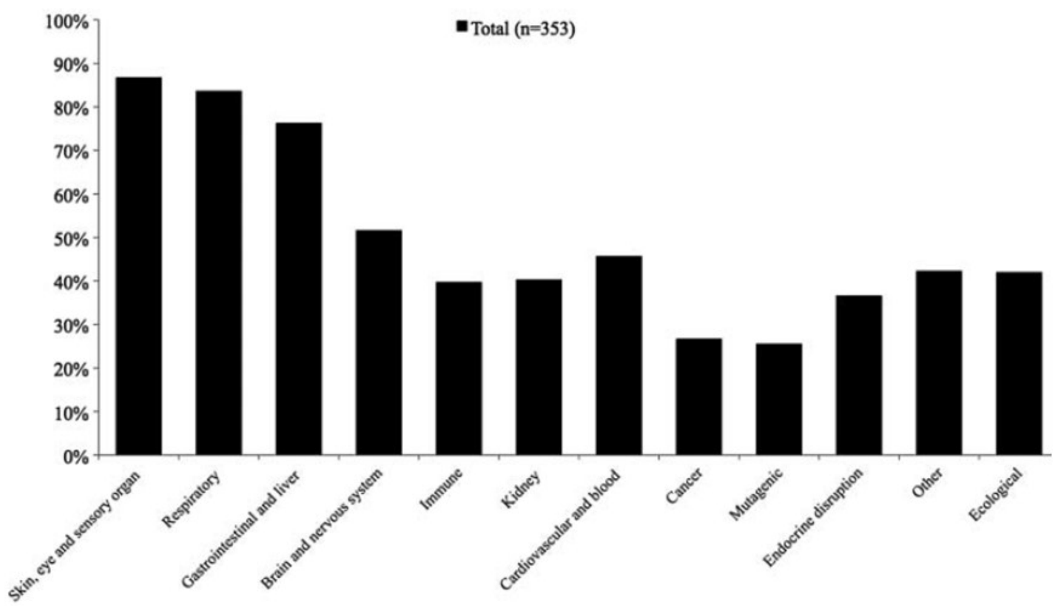

Fig. 2-2. Possible health effects of chemicals natural gas operations (Colborn et al., 2011)

Colborn's paper provides a list of 71 potentially hazardous drilling and fracturing chemicals, i.e., those that are associated with 10 or more health effects.

Natural gas drilling and hydraulic fracturing chemicals with 10 or more health effects

Chemicals Used in Natural Gas Development

2,2',2''-Nitrilotriethanol
2-Ethylhexanol
5-Chloro-2-methyl-4-isothiazolin-3-one
Acetic acid
Acrolein
Acrylamide (2-propenamide)
Acrylic acid
Ammonia
Ammonium chloride
Ammonium nitrate
Aniline
Benzyl chloride
Boric acid
Cadmium
Calcium hypochlorite
Chlorine
Chlorine dioxide
Dibromoacetonitrile 1
Diesel 2
Diethanolamine
Diethylenetriamine
Dimethyl formamide
Epidian
Ethanol (acetylenic alcohol)Ethyl mercaptan
Ethylbenzene
Ethylene glycol
Ethylene oxide
Ferrous sulfate
Formaldehyde
Formic acid
Fuel oil #2
Glutaraldehyde
Glyoxal
Hydrodesulfurized kerosene
Hydrogen sulfide
Iron
Isobutyl alcohol (2-methyl-1-propanol)
Isopropanol (propan-2-ol)
Kerosene
Light naphthenic distillates, hydrotreated
Mercaptoacidic acid
Methanol
Methylene bis(thiocyanate)
Monoethanolamine
NaHCO3
Naphtha, petroleum medium aliphatic
Naphthalene
Natural gas condensates
Nickel sulfate
Paraformaldehyde
Petroleum distillate/naphtha
Phosphonium, tetrakis(hydroxymethyl)-sulfate
Propane-1,2-diol
Sodium bromate
Sodium chlorite (chlorous acid, sodium salt)
Sodium hypochlorite
Sodium nitrate
Sodium nitrite
Sodium sulfite
Styrene
Sulfur dioxide
Sulfuric acid
Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (Dazomet)
Titanium dioxide
Tributyl phosphate
Triethylene glycol
Urea
Xylene

Ethylene glycol monobutyl ether (2-BE)	Petroleum distillate naptha

Table 2-3. Chemicals used in natural gas development (Colborn et al., 2011).

While Colborn and her co-workers focused on chemicals used in natural gas development, the chemicals used to fracture oil wells are very similar or the same. Information regarding hydraulic fracturing fluid chemicals posted on the FracFocus[4] web site indicates that Bakken Shale oil wells may contain toxic chemicals such as hydrotreated light distillate, methanol, ethylene glycol, 2-butoxyethanol (2-BE), phosphonium, tetrakis(hydroxymethyl)-sulfate (aka phosphonic acid), acetic acid, ethanol, and napthlene

Surface Water and Soil Contamination:

Spills of fracturing chemicals and wastes during transportation, fracturing operations and waste disposal have contaminated soil and surface waters. In 2013, 41 spills impacted surface water in Colorado alone. This section provides a few examples of spills related to hydraulic fracturing that have led to environmental impacts (Ferner, 2014).

Two spills kill fish: In September 2009, Cabot Oil and Gas spilled hydraulic fracturing fluid gel LGC-35 twice at the company's Heitsman gas well. The two incidents released between 6,000 and 8,000 gallons of the fracturing fluid, polluting Stevens Creek (near Domock, PA) resulting in a fish kill. LGC-35, a well lubricant used during the fracturing process. A third spill of LGC-35 occurred a week later, but

[4] http://www.fracfocusdata.org/DisclosureSearch/

did not enter the creek. As a consequence, Cabot faced $4,000 in civil penalties and $915 in emergency response costs levied by the Pennsylvania Department of Environmental Protection (DEP) (Wilber, 2009).

In another incident, a wastewater pit overflowed at Atlas Resources' Cowden 17 gas well, and an unknown quantity of hydraulic fracturing fluid wastes entered Dunkle Run, a "high quality watershed". The company failed to report the spill. In August 2010 the Pennsylvania Department of Environmental Protection (DEP) levied a $97,350 fine against Atlas Resources (2010a; Wilber, 2012).

Another fracturing fluid spill impacts a high quality waterway: In May 2010, Range Resources was fined was fined $141,175 for failing to immediately notify the Pennsylvania Department of Environmental Protection when the company spilled 250 barrels of diluted fracturing fluids due to a broken joint in a transmission line. The fluids flowed into an unnamed tributary of Brush Creek in Washington County Pennsylvania, killing at least 168 fish, salamanders and frogs. The watercourse is designated as a warm-water fishery under Pennsylvania's special protection waters program (Rahm, 2011).

Fracturing fluids affect soil and pond: In May 2011, a mechanical problem at a Pennsylvania natural gas well caused thousands of gallons of briny water and fracking fluid of unknown composition to spew out of the well, overwhelm containment facilities and flow across a field and into a pond. The local emergency management agency told seven families to evacuate their homes. It took a response team -- Houston-based Boots and Coots -- 13 hours to reach the site. Six days went by before workers were able to seal the leak and replace the wellhead (Kusnetz, 2011).

Groundwater Contamination:

As mentioned previously, hydraulic fracturing is used in many coalbed methane (CBM) production areas. Some coal beds contain groundwater of high enough quality to be considered underground sources of drinking water (USDWs).

In 2004, the U.S. Environmental Protection Agency (EPA) released a final study on Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. In the study, EPA found that ten out of eleven CBM basins in the U.S. are located, at least in part, within USDWs. Furthermore, the EPA determined that in some cases, hydraulic fracturing chemicals are injected directly into USDWs during the course of normal fracturing operations (see chapter 1 for a listing of fracking chemicals).

Calculations performed by EPA and reported in the study show that at least nine hydraulic fracturing chemicals may be injected into or close to USDWs at concentrations that pose a threat to human health. The chart below is a reproduction of the data from the EPA draft study. Chemicals may be injected at concentrations that are anywhere from 4 to almost 13,000 times the acceptable concentration in drinking water. Not only does the injection of these chemicals pose a short-term threat to drinking water quality, it is quite possible that there could be long-term negative consequences for USDWs from these fracturing fluids. According to the EPA study, studies conducted by the oil and gas industry, and interviews with industry and regulators, 20 to 85% of fracturing fluids may remain in the formation, which means the fluids could continue to be a source of groundwater contamination for years to come.

The potential long-term consequences of dewatering and hydraulic fracturing on water resources have been summed up by professional hydrogeologist who spent 32 years with the U.S. Geological Survey:

At greatest risk of contamination are the coalbed aquifers currently used as sources of drinking water. For example, in the Powder River Basin (PRB) the coalbeds are the best aquifers. CBM production in the PRB will destroy most of these water wells; BLM predicts drawdowns...that will render the water wells in the coal unusable because the water levels will drop 600 to 800 feet. The CBM production in the PRB is predicted to be largely over by the year 2020. By the year 2060 water levels in the coalbeds are predicted to have recovered to within 95% of their current levels; the coalbeds will again become useful aquifers. However, contamination associated with hydrofracturing in the basin could threaten the usefulness of the aquifers for future use.

As mentioned previously, more than 90% of fracking fluids remain in the ground. Some fracturing gels remain stranded in the formation, even when companies have tried to flush out the gels using water and strong acids. Also, studies show that gelling agents in hydraulic fracturing fluids decrease the permeability of coals, which is the opposite of what hydraulic fracturing is supposed to do (i.e., increase the permeability of the coal formations). Other similar, unwanted side effects from water- and chemical-based fracturing include: solids plugging up the cracks; water retention in the formation; and chemical reactions between the formation minerals and stimulation fluids. All of these cause a reduction in the permeability in the geological formations.

Air Quality:

In many oil and gas producing regions, there has been a degradation of air quality as drilling increases. For example, in Texas, high levels of benzene have been measured in the air near wells in the Barnett Shale gas fields. These volatile air toxics may be originating from a variety of gas-field source such as separators, dehydrators, condensers, compressors, chemical spills, and leaking pipes and valves.

Increasingly, research is being conducted on the potential air emissions released during the fracturing flow back stage, when wastewater returns to the surface. Shales contain numerous organic hydrocarbons, and additional chemicals are injected underground during shale gas drilling, well stimulation (e.g., hydraulic fracturing), and well workovers.

The Pittsburgh University Center for Healthy Environments and Communities (CHEC) has been examining how organic compounds in the shale can be mobilized during fracturing and gas extraction processes. According to the CHEC researchers, these organic compounds are brought to the surface in the fracturing flowback or produced water, and often go into open impoundments (frac ponds), where the waste water, "will offgas its organic compounds into the air. This becomes an air pollution problem, and the organic compounds are now termed Hazardous Air Pollutants (HAP's)."

The initial draft of the New York draft supplemental environmental impacts statement related to drilling in the Marcellus Shale (which is no longer available on-line) included information on modeling of potential air impacts from fracturing fluid wastes stored in centralized impoundments. One analysis looked at the volatile organic compound methanol, which is known to be present in fracturing fluids such as surfactants, cross-linkers, scale inhibitors and iron control additives. The state calculated that a centralized fracturing flowback waste impoundment serving 10 wells (5 million gallons of flowback per well) could have an annual emission of 32.5 tons of methanol.

The U.S. EPA reports that "chronic inhalation or oral exposure to methanol may result in headache, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, visual disturbances (blurred vision), and blindness in humans." Open pits, tanks or impoundments that accept flowback wastes from one well would have a much smaller emission of volatile organic compounds (VOC) like methanol than facilities accepting wastes from multiple wells. But there are centralized flowback facilities like those belonging to Range Resources in Washington County, Pennsylvania that have been designed for "long-term use," and thus, are likely to accept wastes from more than one well.

New York's air modeling further suggested that the emission of Hazardous Air Pollutants (HAPs) from centralized flowback impoundments could exceed ambient air thresholds 1,000 meters (3,300 feet) from the impoundment, and could cause the impoundment to qualify as a major source of HAPs.

Methanol is just one of the VOCs contained in flowback water. The combined emissions from all VOCs present in flowback stored at centralized impoundments could be very large, depending on the composition of the fracturing fluids used at the wells. Data released on flowback water from wells in Pennsylvania reveal that numerous volatile organic chemicals are returning to the surface, sometime in high concentrations. The Pennsylvania Department of Environmental Protection looked for 70 volatile organic compounds in flowback, and 27 different chemicals showed up.

Again referring to the Colburn paper, 37% of the chemicals used during natural gas drilling, fracturing and production (for which health data were available) were found to be volatile, with the ability to become airborne. they compared the potential health impacts of volatile chemicals with those chemicals more like to be found in water (i.e., chemicals with high solubility). Their study reported that “far more of the volatile chemicals (81%) can cause harm to the brain and nervous system. 71% of the volatile chemicals can harm the cardiovascular system and blood, and 66% can harm the kidneys,” producing a profile that “displays a higher frequency of health effects than the water soluble chemicals.” The researchers add that the chance of exposures to volatile chemicals are increased by case they can be inhaled, ingested and absorbed through the skin. It’s worth noting that citizens of the gas field are experiencing health effects related to volatile chemicals from pits (Colborn et al., 2011).

In 2005, numerous Colorado residents experienced severe odors and health impacts related to flowback and drilling pits and tanks in Garfield County. According to Dion and Debbie Enlow complained to the Colorado Oil and Gas Conservation Commission about odors from a Barrett wellpad upwind from their home. The pad had four wells that were undergoing completion/hydraulic fracturing. Dion Enlow complained to the company that the smell was so bad that "I can't go outside and breathe."

In Pennsylvania, a fracturing flowback wastewater pit just beyond June Chappel’s property line created odors similar to gasoline and kerosene, which forced her inside, left a greasy film on her windows, on one occasion created a white dust that fell over her yard. Chappel and her neighbors lived with the noxious odors until they hired an attorney and Range Resources agreed to remove the impoundment.

In March 2010, a fracturing flowback wastewater impoundment in Washington County, Pennsylvania caught fire and exploded producing a cloud of thick, black smoke that could be seen miles away. For several days prior to the explosion nearby citizens had tried to alert state officials about noxious odors from the impoundment that were sickening their families, but “their voicemail boxes were full.”

Waste Disposal:

It has been reported that anywhere from 25 – 100% of the chemical-laced hydraulic fracturing fluids return to the surface from Marcellus Shale operations (Cooley, 2012). Based on the data in a paper by Nicot et al., Table 2-4 clearly shows the variability of water use per well in Texas plays; however, the magnitude of water usage per well is clear (Nicot and Scanlon, 2012).

Texas Shale Play	Water expenditure per well (Millions of gallons)		
	Low Value	Median Value	High Value
Barnett Shale	<1	2.6	>8
Haynesville and Bossier Shale	<1	5.5 – 6	>10
Eagle Ford Shale	1	6 – 6.5	13
Woodford, Pearsall, and Barnett-PB Shale	<1	.75 – 1	<5

Table 2-4. Water usage in Texas shale plays per well (Nicot and Scanlon, 2012; Cooley, 2012)

This means that for some shale gas wells, millions of gallons of wastewater are generated, and require either treatment for re-use, or disposal. As the industry expands, the volume of waste generated is also increasing rapidly. Between 2010 and 2011, the waste volume increased by 70% in Pennsylvania to reach more than 610 million gallons.

The sheer volume of wastes, combined with high concentrations of certain chemicals in the flowback from fracturing operations, are posing major waste management challenges for the Marcellus Shale states. Also, the US Geological Survey has found that flowback may contain a variety of formation materials, including brines, heavy metals, radionuclides, and organics, which can make wastewater treatment difficult and expensive (Howarth et al., 2011a; Brown, 2014).

According to an article in ProPublica, New York City's Health Department has raised concerns about the concentrations of radioactive materials in wastewater from natural gas wells (Lustgarten, 2009). In a July, 2009 letter obtained by ProPublica, the Department wrote that "Handling and disposal of this wastewater could be a public health concern." The letter also mentioned that the state may have difficulty disposing of the waste, that thorough testing will be needed at water treatment plants, and that workers may need to be monitored for radiation as much as they might be at nuclear facilities (Lustgarten, 2009).

Options for disposal of radioactive flowback or produced water include underground injection in Class II UIC wells and offsite treatment (refer to Table 2-2 for UIC classifications). The U.S. Environmental Protection Agency has indicated that Class II UIC injection disposal wells are uncommon in New York, and existing wells aren't licensed to receive radioactive waste. A research article by Ellsworth published in a 2013 issue of Science indicates that injection wells have also been linked to earthquakes (Ellsworth, 2013). In terms of offsite treatment, it is not known if any of New York’s water treatment facilities are capable of handling radioactive wastewater. Pennsylvania state regulators and the natural gas industry are also facing challenges regarding how to ensure proper disposal of the millions of gallons of chemical-laced wastewater generated daily from hydraulic fracturing and gas production in the Marcellus shale. Drinking water treatment facilities in Pennsylvania are not equipped to treat and remove many flowback contaminants, but rather, rely on dilution of chlorides, sulfates and other chemicals in surface waters used for drinking water supplies.

During the fall of 2008, the disposal of large volumes of flowback and produced water at publicly owned treatment works (POTWs) contributed to high total dissolved solids (TDS) levels measured in Pennsylvania’s Monongahela River and its tributaries. Studies showed that in addition to the Monongahela River, many of the other rivers and streams in Pennsylvania had a very limited ability to assimilate additional TDS, sulfate and chlorides, and that the high concentrations of these constituents were harming aquatic communities. Research by Carnegie Mellon

University and Pittsburgh Water and Sewer Authority experts suggests that the natural gas industry has contributed to elevated levels of bromide in the Allegheny and Beaver Rivers. Bromides react with disinfectants used by municipal treatment plants to create brominated trihalomethanes, which have been linked to several types of cancer and birth defects.

In August of 2010, Pennsylvania enacted new rules limiting the discharge of wastewater from gas drilling to 500 milligrams per liter of total dissolved solids (TDS) and 250 milligrams per liter for chlorides. The number of municipal facilities allowed to take drilling and fracking wastewater has dropped from 27 in 2010 to 15 in 2011. Disposal of drilling and fracking waste water is going to continue to present a challenge to local and state governments as more wells are developed across the country.

Chemical Disclosure:

Fracking companies have been reluctant to share the chemical composition of their fracking fluids often citing trade secret protection. A Natural Research Defense Council paper published in 2012 explains disclosure and rules on enforcement (McFeeley, 2012). One potentially frustrating issue for surface owners is that it has not been easy to find out what chemicals are being used during the hydraulic fracturing operations in your neighborhood. According to the Natural Resources Defense Council, in the late 1990s and early 2000s attempts by various environmental and ranching advocacy organizations to obtain chemical compositions of hydraulic fracturing fluids were largely unsuccessful because oil and gas companies refused to reveal detailed information citing proprietary protection (McFeeley, 2012).

Hydraulic Fracturing Best Practices:

From a public health perspective, if hydraulic fracturing stimulation takes place, the best option is to fracture formations using sand and water without any additives, or sand and water with non-toxic additives. Non-toxic additives are being used by the offshore oil and gas industry, which has had to develop fracturing fluids that are non-toxic to marine organisms. It is common to use diesel in hydraulic fracturing fluids. This should be avoided, since diesel contains the carcinogen benzene, as well as other harmful chemicals such as naphthalene, toluene, ethylbenzene and xylene. According to the company Halliburton, "Diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system." It is technologically feasible to replace diesel with non-toxic "delivery systems," such as plain water. According to the EPA, "Water-based alternatives exist and from an environmental perspective, these water-based products are preferable." For example, Air Products offers a Nitrogen based fracking fluid with a gas phase of nitrogen in the range of 53% to 95% by volume. Thus, alternatives such as the nitrogen based fracking fluid by Air Products can drastically decrease water consumption (Kothare, 2012).

2.1.2 Fire and Gas Safety systems (FGS)

Before we can discuss FGS systems, highlights of the IEC 61511 technical standard must be presented. The IEC (International Electrotechnical Commission) is a worldwide standardization committee that collaborates closely with the Organization for Standardization (ISO). IEC 61511 addresses safety instrumented systems which deploy electrical/electronic/programmable electronic systems that leverage logic solvers. This standard also addresses instrumented sensors systems with safety as a goal. The standard further describes the need for a: risk assessment, operational requirements, framework, and safety management / activities (Smith and Simpson, 2010). In the context of IEC 61511, FGS systems are considered to be mitigative SIS (Safety Instrumented System); in other words, they respond to an event **after** it has occurred. This has applications in industrial settings where personnel must be evacuated or control elements can finalize an Emergency Shut Down (ESD) as described in section 2.1.3.

IEC 61508 is a sister standard of IEC 61511 with a focus on the design of hardware and software for safety system while IEC 61511 is relevant to users and integrators. Together, these two standards support the internationally recognized development and deployment of SIS(s) (Gall, 2008).

2.1.3 Emergency Shut Down (ESD) Systems

An ESD System is designed to minimize the impact of an industrial anomaly after it has occurred. When integrated with logic solvers running voting functionality, ESD systems can function in preventative manner to control multi- dimensional impacts. The system leverages sensor, logic solvers, and final control elements also called a safety instrumented function (SIF). Each SIF works to reduce risk by preventing a specific hazard from occurring if called upon by the logic solver. Further, a SIL (Safety Integrity Level) is set for a certain facet of the system that centers around availability and risk reduction (Jin et al., 2003), (Goble, 2010).

Safety Integrity Level (SIL)			Availability Required	Risk Reduction Factor	Typical Application
IEC 61508		4	>99.99%	> 10,000	Rail Transportation Nuclear Power
	ANSI / ISA S84	3	99.90-99.99%	1000-10,000	Utility Boiler
		2	99.0-99.90%	100-1,000	Industrial Boilers
		1	90.00-99.00%	10-100	Chemical Process

Table 2-5. Safety Integrity Levels (Jin et al., 2003)

By quickly reviewing Table 2-5, it's clear to see that the decision of a SIL falls within the realm of design; this is because IEC 61508 focuses on hardware and software for a system rather than integration.

From a process planning standpoint let us now focus on Fig. 2-3. Here the practitioner is to adhere to IEC 61511 and design in requirements and a general philosophy for functionality of the FGS system. The first step in designing a system in accordance with Fig. 2-3 is to codify operational requirements for the FGS system. By following IEC 61511 and a design flowchart like Fig. 2-3 (left hand side), a systems engineer can refine a FGS solution in line with operational goals of risk and safety. Furthermore, critical questions can be answered before costly hardware and software solutions are implemented by following IEC 61508. Some items for consideration for during this stage of the FGS process are (Kenexis, 2013):

- Regulatory Requirements
- Standardized Design Practices
- Corporate standards or policy
- Project management and risk policy

- Process Hazards Analysis (PHA) Recommendations
- Recommendations from an Auditor; hazard insurance or regulatory oversight

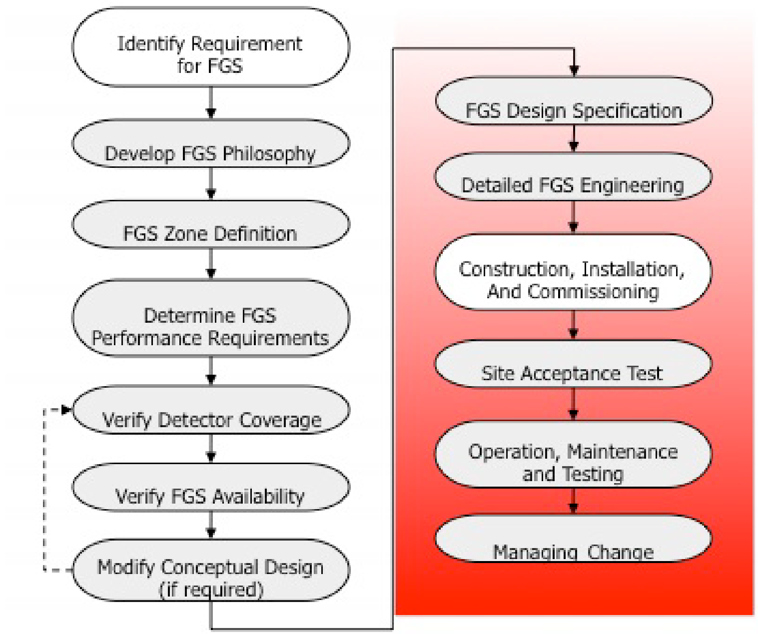

Fig. 2-3. Design and implementation of FGS (Kenexis, 2013).

Fig. 2-4 serves as the backdrop for a disccussion of Independent Protection Layers (IPL). Each IPL can be passive or active, but must be independent of all others. Each IPL must play some sort of role in mitigation of a particular risk or hazard (Summers, 2003). The following list outlines the baisc criteria of an IPL according to a paper by Summers (Summers, 2003).

Criteria of an Independent Protection Layer (IPL) according to Summers (Summers, 2003)

• Specificity. The IPL is capable of detecting and preventing or mitigating the consequences of specified, potentially hazardous event(s), such as a runaway reaction, loss of containment, or an explosion.

• Independence. An IPL is independent of all the other protection layers associated with the identified potentially hazardous event. Independence requires that the performance is not affected by the failure of another protection layer or by the conditions that caused another protection layer to fail. Most importantly, the protection layer is independent of the initiating cause.

• Dependability. The protection provided by the IPL reduces the identified risk by a known and specified amount.

• Auditability. The IPL is designed to permit regular periodic validation of the protective function.

Now that an IPL has been defined, its place in a risk mitigation strategy becomes more apparent. At both the design and operational phases of IPL solutions, systems engineers and project managers work together to to define the risk strategy. Probabailites can be assgned to the success and failure of each IPL; this will result in a nested calculation which reviels the current operational risk of a system.

Additional details will be presented in Chapter 4 when research methodogies are presented.

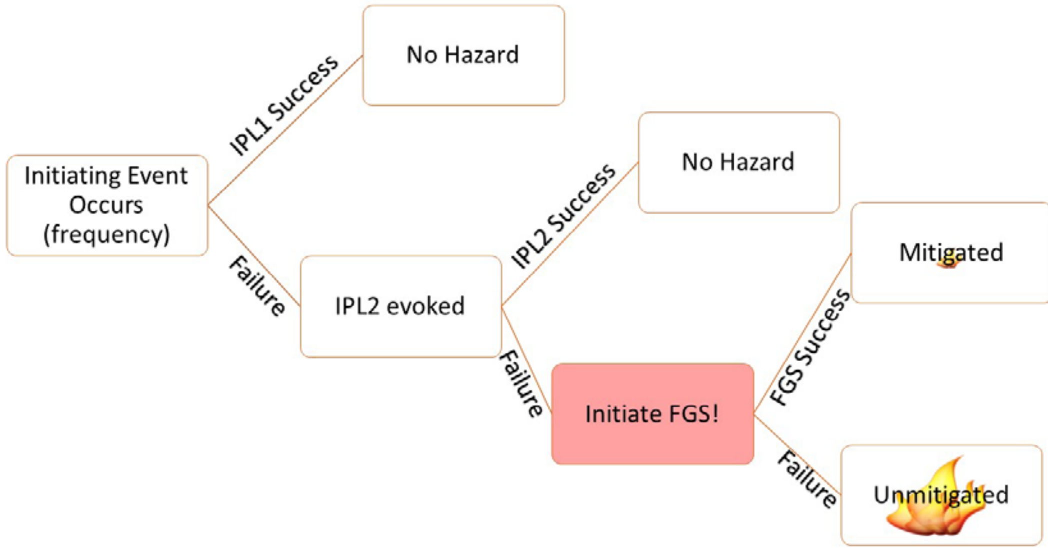

Fig. 2-4. FGS is like an IPL (Independent Protection Layer) (Kenexis, 2013).

Fig. 2-5 is in essence a framework for the equations shown in Eq. 2-1. A graphical representation of safety sensor systems can help the project manager understand the dynamic risk posture as operational conditions change at filed sites. The need for additional sensors can be assessed or coverage (footprints) of sensors can be adjusted at compensate for an unacceptable risk level. **Sensor-augmented risk management"** systems can be implemented with concepts shown in Fig 2-4 and Fig 2-5. More details will be discussed in chapter 4 and 5 when methodology and results are presented.

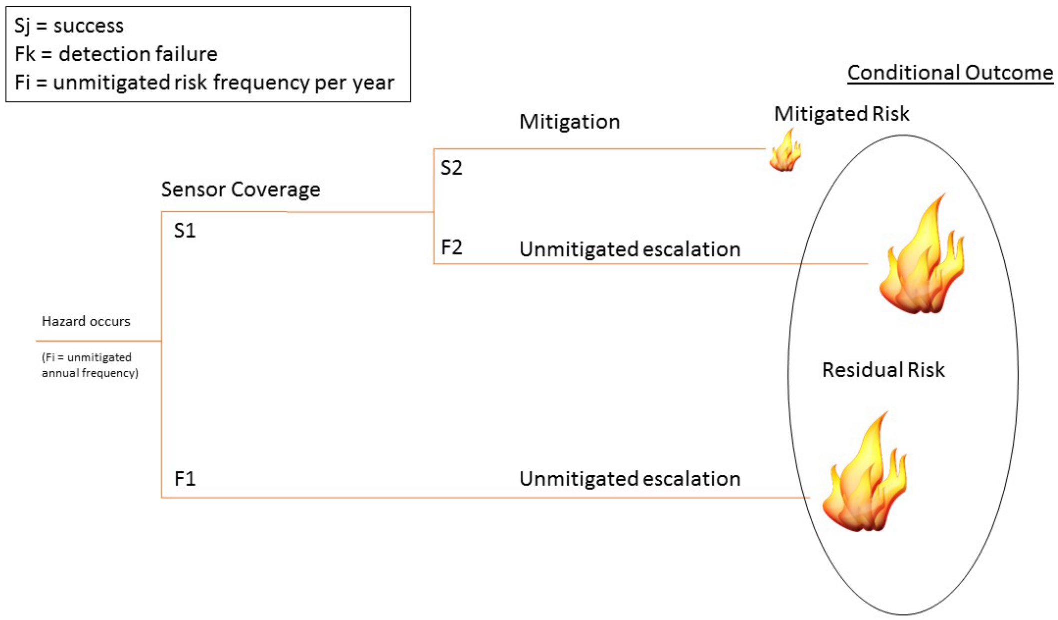

Fig. 2-5. Modeling Risk in FGS engineering (Kenexis, 2013).

From a risk and analysis equations 2-1 through 2-3 directly support Fig. 2-5 and help FGS engineers realize the inherent risk associated with a particular design solution.

Eq. 2-1	Fi*(F1+S1*F2) = Residual Risk (per year)
Eq. 2-2	Fi*(S1*S2) = Mitigated Risk (per year)
Eq. 2-3	S1*S2 = "FGS Effectiveness"

Eqs. 2-1 through 2-3. Risk equations for an FGS system (Kenexis, 2013).

By using these equations and derivatives thereof (to be shown in Chapter 5), it is possible to model an FGS system in conjunction with sensors. More specifically, the model can lend some consideration to the accuracy and number of sensors required to reduce the residual risk.

Sensor performance and coverage along with FGS effectiveness are of paramount importance to this model. Risk can be calculated by using risk integration event tree summation. Obviously without the proper sensor in place, a particular risk modality would be overlooked and by definition result in a residual risk. For example, natural events such as lightning strikes are an understood risk; however, if a sensor system lacks detection of this phenomenon, then the risk cannot be countered. Better still, if a system had the ability to predict the likelihood of such an event then corrective measures can be taken.

2.1.4 Lightning and the future of hydraulic fracturing

As published by Romps, et al. in 2014 Science article, cloud-ground lightning strikes are predicted to increase by 50% during the 21st century due to global warming (Romps et al., 2014). As Fig. 2-8 clearly shows, cloud-ground lightning strikes as reported by the National Lightning Detection Network (NLDN) differ significantly across the country.

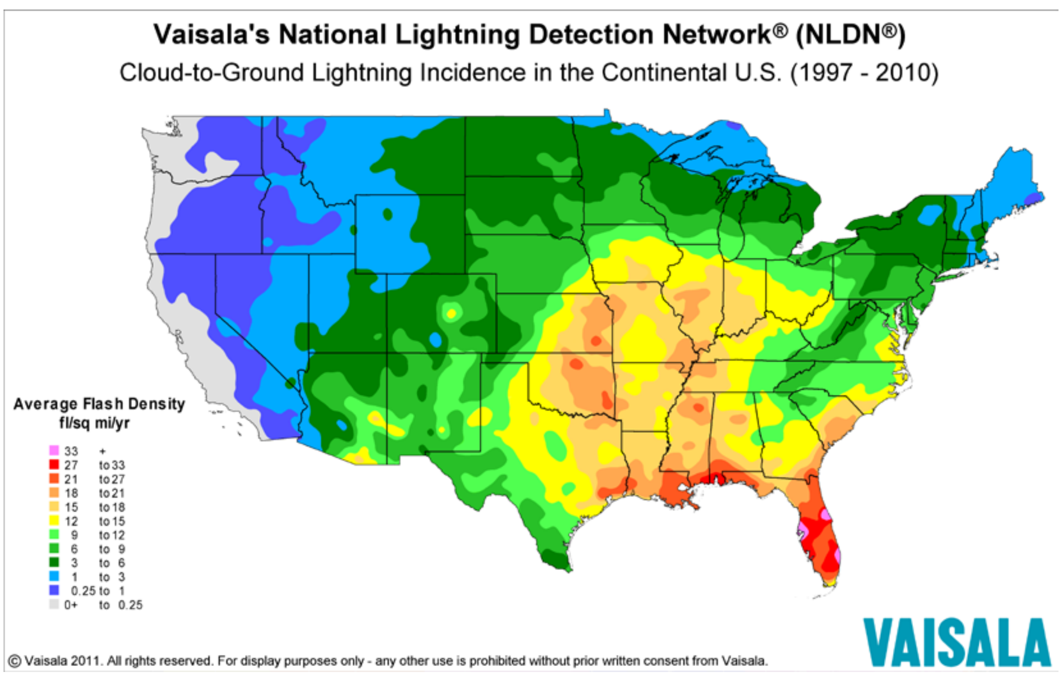

Fig. 2-6. Incidences of cloud-ground across the United States[5]

According to a document on the NOAA Lightning Safety website[6] Lightning is responsible for an average of 55-60 fatalities in the United States.

- Insurance losses exceed $1 billion annualy

There are about 25 million cloud-ground lightning strikes in the U.S. each year[7].

The Lightning Safty site at NOAA continues to explain that injuries to people tend to follow occupations. Obviously people who work outside are at the greatest risk for lightning injury. The outlined occupations are considered to have the most exposure to lightning injury.

- Logging
- Explosive handling or storage
- Heavy equipment operation
- Plumbing and pipe fitting
- Construction and building maintenance
- Farming and field labor
- Telecommunications field repair

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[5]http://www.vaisala.com/en/products/thunderstormandlightningdetectionsystems/Pages/NLDN.aspx

[6] http://www.lightningsafety.noaa.gov/resources/ttl6-10.pdf

[7] http://www.lightningsafety.noaa.gov/

- Power utility field repair

If Fig. 2-6 is superimposed upon the map of current and prospective shale plays (Fig. 2-7), the importance of lightning in relation to fracking becomes apparent.

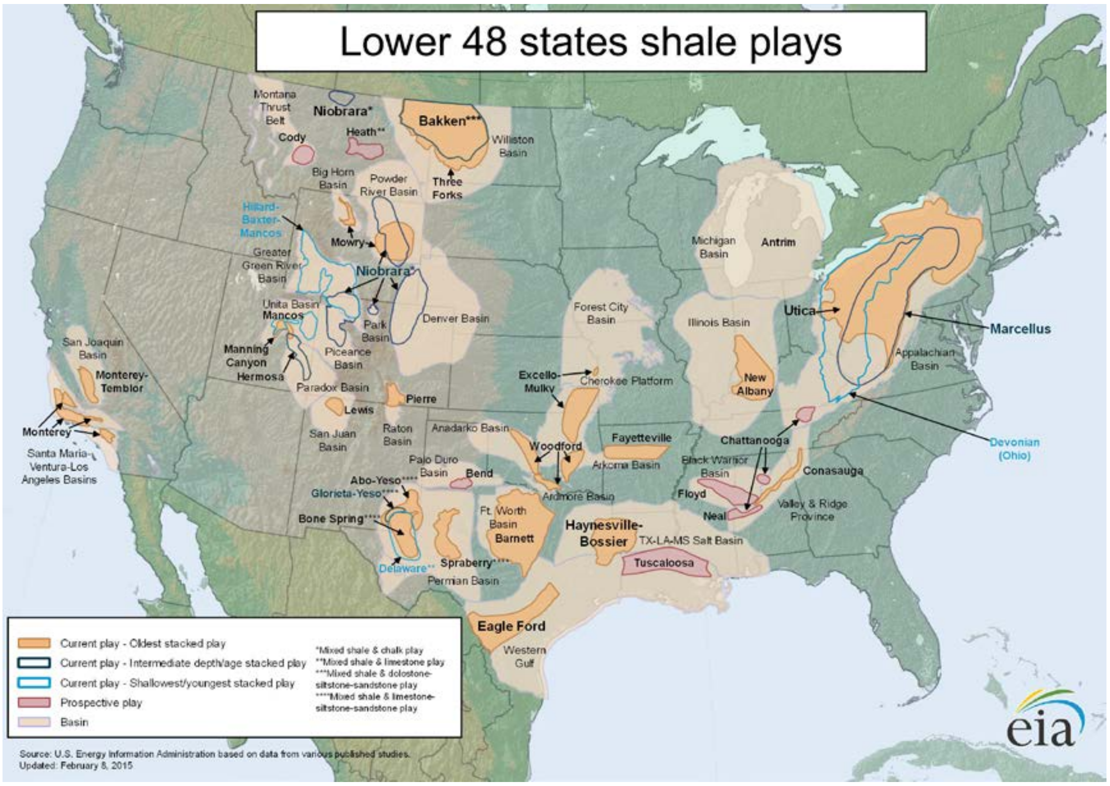

Fig. 2-7. Current and prospective U.S. shale plays in 2015 based on the EIA[8]

As was shown at the outset of this sub-section, global warming is predicted to cause a 50% increase in cloud-ground lightning incidences over this century (Romps et al., 2014). Shale resourced hydrocarbons are expected to play an increasingly larger role in our energy economy for the foreseeable future. In an interview with CNN on

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[8] U.S. Energy Information Administration (EIA) 2015
http://www.eia.gov/oil_gas/rpd/shale_gas.jpg

April 13th, 2015, Tom Kloza, Chief Oil Analyst at the Oil Price Information Service agrees with a forecast (Rystad Energy)[9] for U.S. oil production to rise to a new record this year by saying they are "very reasonable." This will make the U.S. the third-largest crude oil producer, trailing only Saudi Arabia and Russia. If total hydrocarbon production is considered, the U.S. should keep its title as the world's top oil producer.[10] By reviewing Fig. 2-8, the rapid growth in oil and gas production from U.S. hydro fracked shale plays becomes apparent.

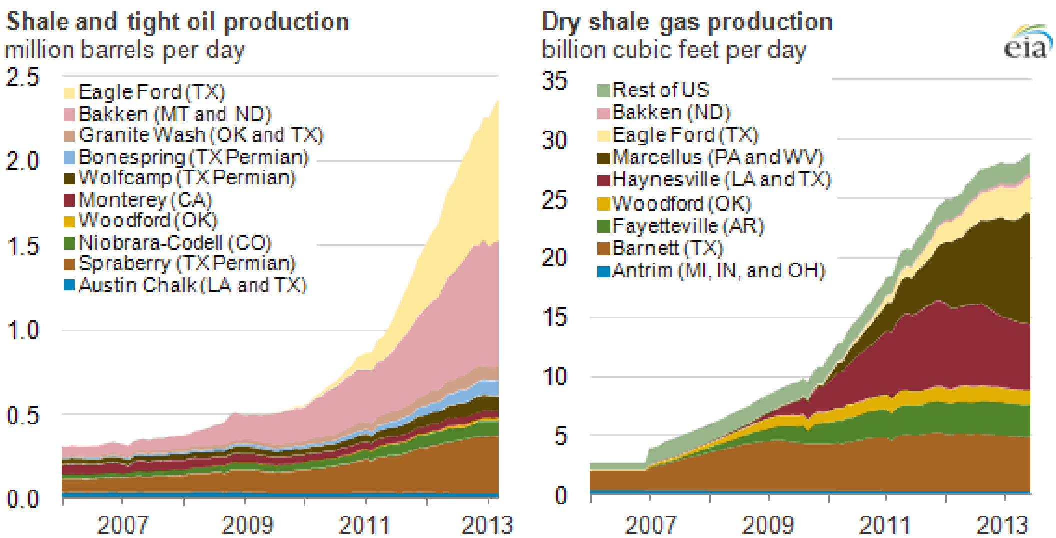

Fig. 2-8. U.S. Energy Information Administration (EIA) Oil and Gas production[11]

Cloud-ground lightning has been predicted to increase, while fracking for oil and gas is clearly on the assent. These intersecting factors alone should concern the operators of vulnerable hydrocarbon batteries; however, there is one additional factor. If Fig. 2-6 and Fig. 2-7 are overlayed, as shown in Fig. 2-9, it quickly becomes

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[9] http://www.rystadenergy.com/
[10] http://money.cnn.com/2015/04/13/investing/us-oil-production-record/index.html
[11] http://www.eia.gov/todayinenergy/detail.cfm?id=13451

clear that prospective fracking sites are located in substantial parts of the lightning prone Deep South.

There is an obvious need for increased lightning “reediness” in the hydro fracking industry.

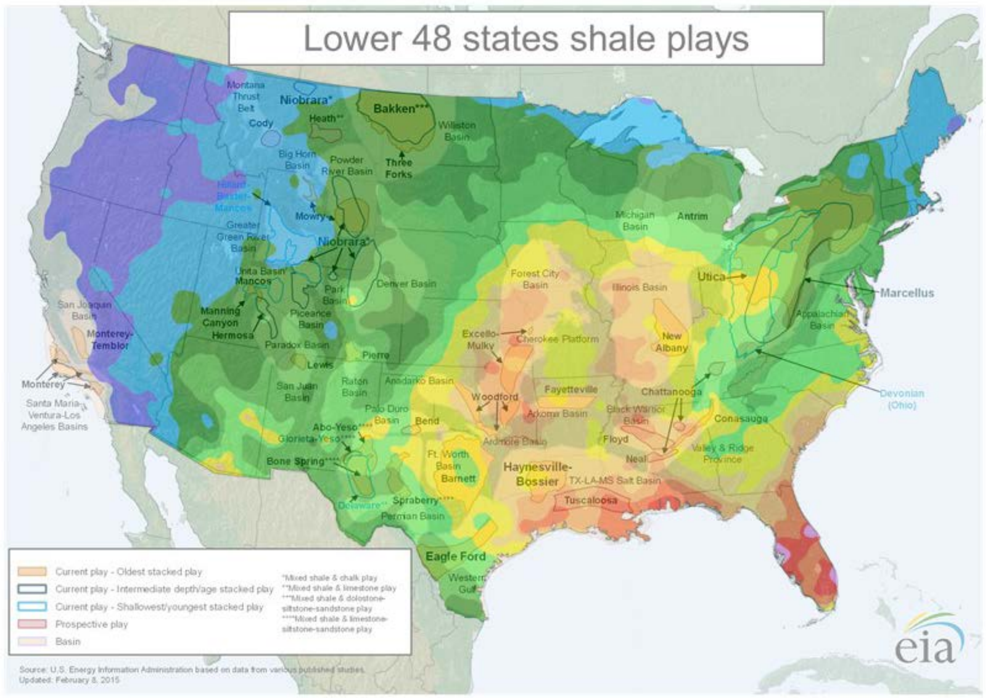

Fig. 2-9. Overlay of lightning risk and shale play maps

2.2 Research Questions to be Answered

Fire and Gas Safety (FGS) systems are widely deployed in industrial environments (Association, 2004). The deployed atmospheric charge and tank charge sensors (to be detailed in Chapter 4) present IPL (Independent Protection Layers) that are analogous to the function and mission of widely accepted FGS systems.

1.) As fracking continues throughout the United States (and world), data is showing that the prevalence of lightning in fracking areas will increase dramatically. Therefore the risk of an explosion – with accompanying financial and environmental consequences – is expected to increase dramatically as well. Is there a way to use sensors and modeling to help minimize the financial and environmental losses and issues? If so, could it be automated?

In order to answer this fundamental question, a number of associated questions must be answered, including:

2.) Develop the driving equations of the intersecting items, such as:

- **probability of lightning strikes,**
- **cost of an environmental incident (pollutant dependent)**
- **well production estimation (temporal dependent)**
- **cost to incumbent organization for an incident (cost to fracking company)**

3.) What are the border implications for sensors and lightning detection beyond hydro fracking hydrocarbon storage?

2.3 Implications of "an Answer"

With research question 1, I will explore a pathway toward minimizing the costs associated with lightning strikes on hydro fracking sites. From the prospective of environmental impacts and risk costs prospective. The answers should provide a pathway toward automation of lightning mitigation systems.

With question 2 answered, fundamental relationships will be realized and thus, the groundwork will be set for understanding how sensors systems with automated mitigation systems will impact the operation of hydro fracking sites. Also of interest is the touch points for these types of systems, and how can they be leveraged by the operations manager in the future. These fundamental questions are important for the design and validation of future such systems.

The implications of an answer to questions 3 will enable a lightning mitigation solution to find applications in large-scale hydrocarbon storage facilities.

2.4 Summary

This chapter detailed chemicals associated with the hydro fracking process for the purposed of understanding the problem space, and to gain an understanding pollution potential from tank accidents. The chapter then introduced the concept of an Independent Protection Layer (IPL) and its relation to automated safety systems. The chapter then introduce the lightning threat in the context of hydro fracking shale plays. In closing, the chapter introduced the research questions for this dissertation.

Chapter 3: Literature Review and Related Activities

This chapter discusses literature relating to hydro fracking tank composition and reviews a detailed assessment of tank accidents. In addition, tank storage standards are presented and conclusions related to unintended volatile contaminants are made toward the end of Section 3.1 Then, In section 3.2 a functional overview of sensors is provided within the context of the human sense of smell. In addition, thermal, chemical and optical sensors are discussed with applications. This is followed by the introduction of sensor touch points for hydro fracking. The chapter closes with a brief discussion of risk and decision trees.

3.1 On-site Petroleum Storage and Safety

In a 2002 paper drafted by Eckert (Eckert, 2004), regulation of petroleum storage tanks between 1983 and 1998 is studied with a view toward compliance. The paper opens by stating “In Canada and the United States it is common for environmental regulators to respond to a detected violation by issuing a warning rather than prosecuting the violator” (Eckert, 2004). So, if an agent faces no financial penalty from a violation, then violations will be common place (Polinsky).

Despite this, the petroleum industry has taken tank safety seriously, and innovative designs have been patented for about 100 years thus far (Clifford, 1918). In this time frame, tank design was focused mostly on mechanical construction from various steel components (1927) and even to some extent the loss of product due to evaporation (Ivan, 1929). More importantly to this research, is the early interest (1916) in petroleum storage tank design related to the prevention of lightning initiated fires (Munn, 1916).

The fracking industry depends both steel and relatively cheap fiberglass storage tanks at the battery. From a practical prospective, fiberglass storage tanks for battery applications have become a common standard; due to their low relative cost and corrosion resistance (Eckert, 2004). As a highly cited paper by Chang et al. states; at 33% of storage tank accidents, lightning stands out as the #1 cause (Chang and Lin, 2006). Chang's detailed paper explores 242 hydro carbon storage tank accidents over decades and complied table 3-1 below. Clearly, lightning stands out as the #1 cause of storage tank accidents. Table 3-1. General cause of hydro carbon storage tank accidents (Chang and Lin, 2006).

Years →	1960-69	1970-79	1980-89	1990-99	2000-03	Total
Lightning	4	10	19	37	10	80
Maintenance/hot work	1	5	9	12	5	32
Operational Error	1	5	6	8	9	29
Equipment Failure	3	1	5	7	3	19
Sabotage	2	5	2	6	3	18
Crack/rupture	0	3	3	3	8	17
Leaks and line rupture	0	3	2	5	5	15
Static electricity	2	1	2	2	5	12
Open flame	1	0	4	2	1	8
Natural disaster	1	2	1	1	2	7
Runaway reaction	2	1	0	2	0	5
TOTAL →	17	36	53	85	51	242

Table 3-1. General cause of hydrocarbon storage tank accidents (Chang and Lin, 2006).

The Occupational Safety & Health Administration (OSHA) under the United States Department of Labor indicates that fiberglass tanks are flammable, and are only suitable for storage of certain types of liquids in rural areas (United States Depatment of Labor - Occupational Saftey & Health Administration, 1993). Further, there use falls under the OSHA 1910.106(b)(1) standard if there use is relegated to underground instillations for many Classes of liquids (United States Depatment of Labor - Occupational Saftey & Health Administration, 1993). In particular, above ground fiberglass storage tanks shall not contain Class I, II or IIIA flammable liquids according to the cited OSHA standard (United States Depatment of Labor - Occupational Saftey & Health Administration, 1993). However, if the tank is assumed to be in a rural area and contain Class IIIB liquids such as crude oil, use is permitted in accordance with the National Fire Protection Association (NFPA) 30 (2015) standard (United States Depatment of Labor - Occupational Saftey & Health Administration, 1993), (National Fire Protection Association (NFPA)).

NFPA 30 (2015) Class	Examples
Class IA	Diethyl Ether, Ethylene Oxide, some light crude oils
Class IB	Motor and Aviation Gasolines, Toluene, Lacquers, Lacquer Thinner
Class IC	Xylene, some paints, some solvent-based cements
Class II	Diesel Fuel, Paint Thinner
Class IIIA	Home Heating Oil
Class IIIB (OK for Fiberglass tanks)	Cooking Oils, Lubricating Oils, Motor Oil

Table 3-2. NFPA 30 (2015) Classes of Flammable and Combustible Liquids (National Fire Protection Association (NFPA)).

Following the recommended practices of NFPA 30 (2015), fiberglass tanks used at fracking site batteries are housed on the surface in rural areas, and from that standpoint, they are considered to be in compliance. However, as Table 3-2 clearly shows, light crude oils and many other shorter chain and more volatile hydro carbons are not Class IIIB. In addition, any dissolved and degassing methane and ethane are also beyond the spirit of NFPA 30 (realizing they are gasses and NFPA 30 does not apply). None the less, these degassing short carbon chain have remarkably low flashpoints, and are extremely flammable (Haynes, 2013). This results in a situation where essentially any ignition source can easily trigger a fire or an explosion. In addition, the battery facility has a rudimentary separation column (shown in figure 3-1) that is intended to mostly remove some volatile contaminants. Thus, the fiberglass tanks clearly hold more than just pure Class IIIB liquids. This mixture can directly exacerbate any tendency towards flammability of the storage tank.

Fig. 3-1. Battery separation column

3.2 An Examination of Sensors Applicable for Use In and Around Hydraulic Fracturing Storage Batteries

3.2.1 Sensors

A block diagram of a generic sensor system is shown in Fig. 3-2, where Grundler has taken the approach of sensors paralleling the functionality of a living organism, prescribed here in its simplest form (Gründler, 2007).

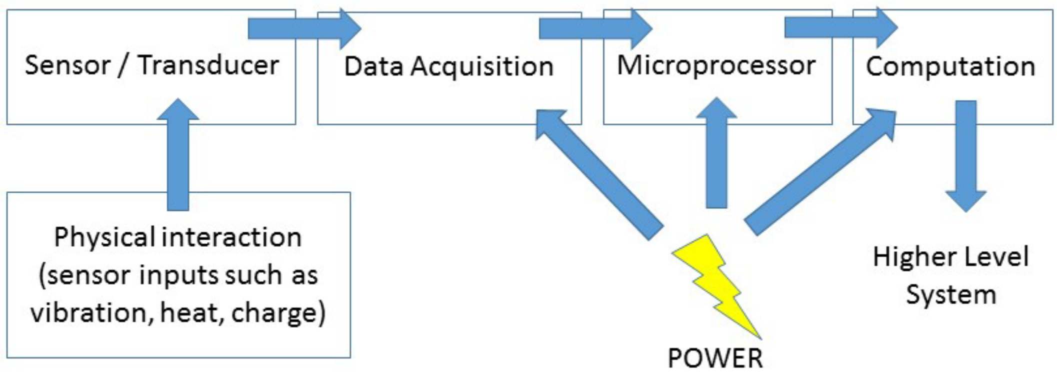

Figure 3-2. Basic anatomy of a sensor – adapted from (Gründler, 2007).

3.2.2 The transducer

The transducer is the "gateway" of a sensor, it connects the sensor to the outside world (see Figure 3-2); it functions by converting one form of energy into another (for our purposes electrical signals) (Agarwal and Lang, 2005). The transduction device simply transforms signals from the sensor into output ready for further processing or display on a Human Machine Interface (HMI) see (Fig 3-3).

Fig. 3-3. Human Machine Interface (HMI) – Rooke 2014

The HMI (Fig. 3-3) is an example of a "Higher Level System" as shown in Fig 3-2. This particular HMI is operational in a "blender" in preparation for fracturing operations. At this interface, a technician can modify the mixture in accordance with best practices and standards (Halliburton, 2013).

3.2.3 Thermal Imaging and Physical sensors

Physical sensors represent a broad class of sensors that measure physical phenomena not limited to: vibration, heat, shock, acceleration, acoustic, and pressure. As a relevant example, Crippa et al. (Crippa et al., 2009) presents the cost/benefit relationship of a fire risk assessment methodology with a decision tree (event tree), and Infrared imaging. Crippa explains that the first step is to establish a realistic level of risk with a particular facility without risk reduction measures in place. Then quantifying the potential for risk reduction that can be realized with a single or multiple risk mitigation measures.

3.2.4 Chemical sensors

One chemical sensor that is always present is your nose. In more scientific terms, your olfactory system is responsible for airborne chemical sensing. At a very basic level olfactory transduction (recall transducer discussion in 3.2.1) is triggered by the binding of odorant molecules to receptors located on the cilia on the surface of specialized olfactory cells (Cagan, 2012; Getchell, 1986). Actions occur on a microscopic scale since olfactory cilia are around 0.25 μm in diameter (Nakamura and Gold, 1987). Recognition of a certain odor is the result of a concert of sensory cells each reporting only a facet of the odor (Lancet, 1986).

This information is transmitted to a region of the forebrain known as the olfactory bulb where "date fusion" takes place, and a vertebrate animal is able to distinguish a particular odor (this is analogous to the microprocessor and computation blocks in Figure 3-2) (Shepherd and Greer, 1998).

By referring to Fig. 3-2 and 3-4 one can see how the olfactory system like any sensor system encodes stimuli (in this case chemical odors) and transduces and transmits this information to higher order centers (as in Fig. 3-2). At present, little is known about the central organization of the olfactory system; in particular, somatic sensory and visual cortices leverage special maps whereas the olfactory bulb transmits signals to higher centers (cerebral cortex) that uses an unknown mechanism to distinguish "features" of various smells (Purves D, 2001).

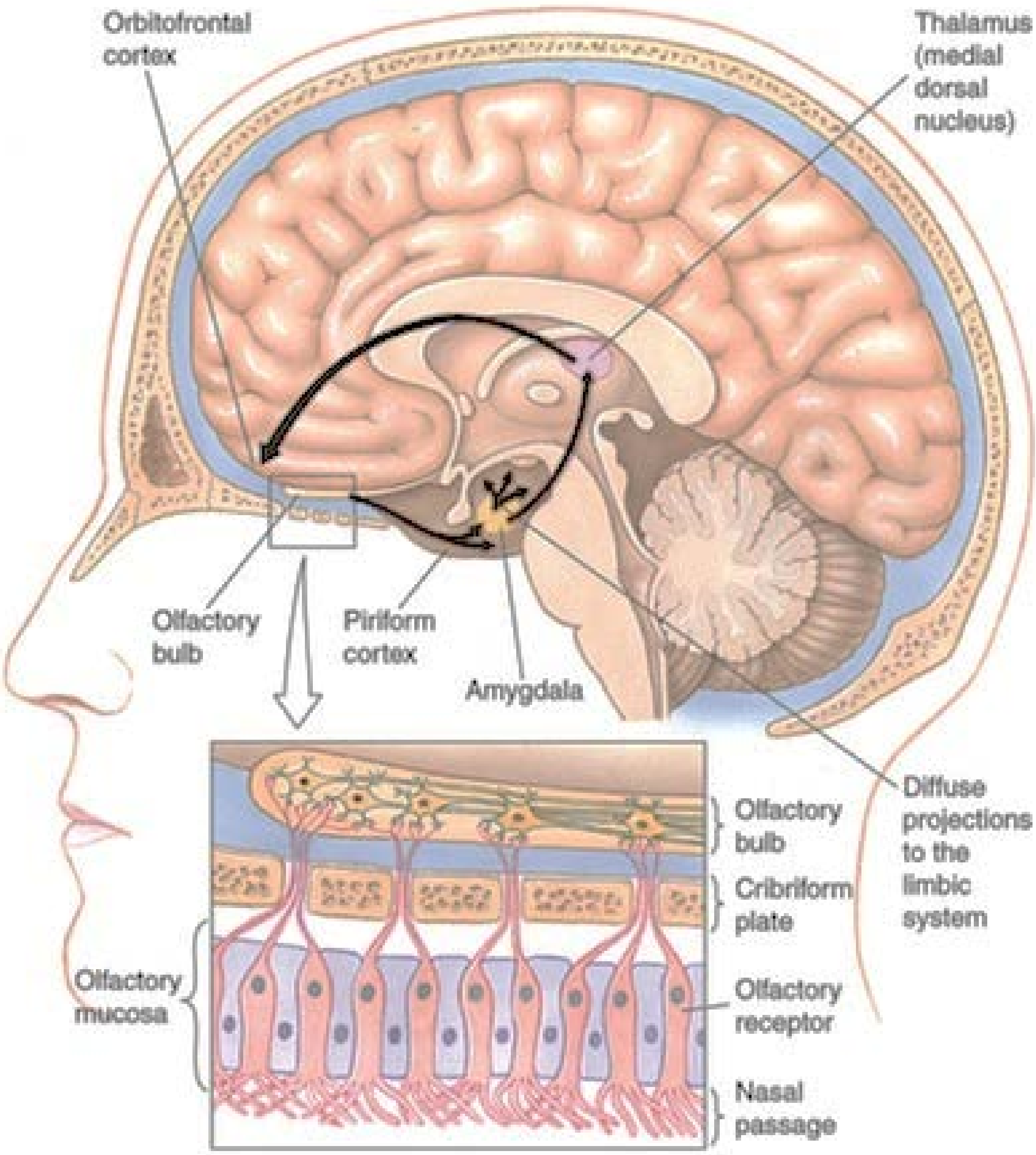

Figure 3-4. Olfactory system (Purves D, 2001).

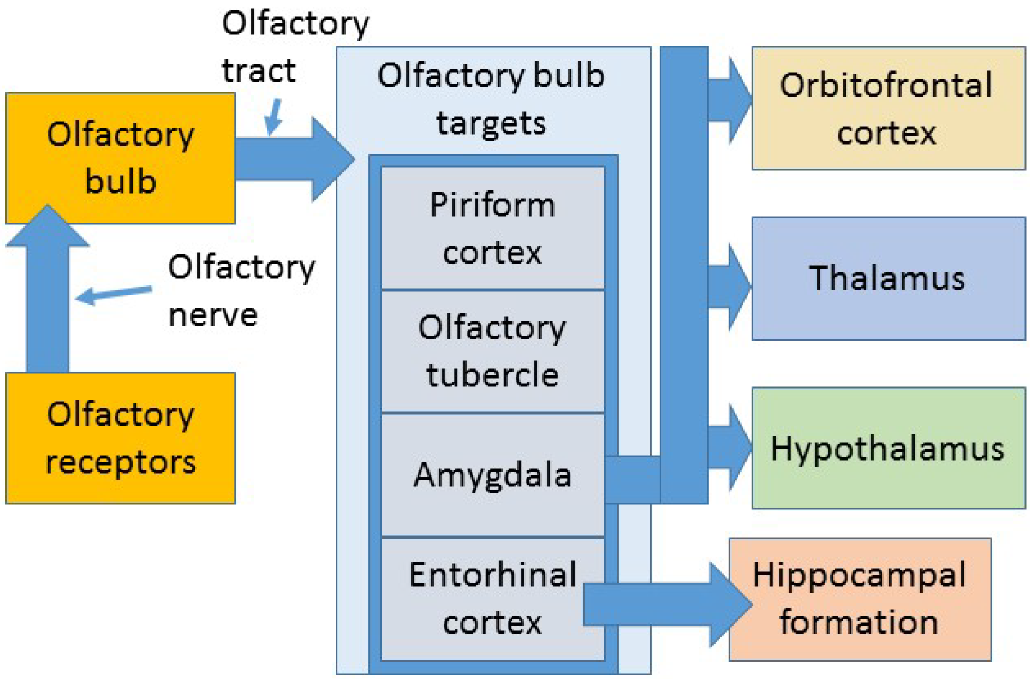

Fig. 3-5. Olfactory systems oriented view (Purves D, 2001).

Indeed, the olfactory sensor system is complicated; yet on the most fundamental level, it parallels manmade sensor systems of almost any kind (refer to Fig. 3-5 and Fig. 3-2).

As we step away from the exclusive world of smell; it can be said that chemical sensors represent a class of devices that provide information concerning the chemical species present in a measurement environment that is typically in the liquid or gas phase (Banica, 2012). However, some chemical sensors including corrosion sensors can function within solid boundaries and even leverage the power of wireless technology to transmit information (Andringa et al., 2005). So, chemical sensors run the gamut when it comes to sensing: solid, liquid, and gas.

As we bring our literature research back to the topic at hand, hydro fracking chemical sensors are primarily used to monitor air, water, and geological phenomenon. Chemical species in the atmosphere surrounding hydro fracking facilities has been of interest to researchers

3.2.5 Fiber Optic Sensors

The discipline of fiber optics is a detailed field, and much of it is beyond the scope of this dissertation. However, a brief overview of the optical fiber from a general prospective shall now be presented. The speed of light is dependent upon the medium of its travel; this helps define the concept of refractive index and its origins date back to the time of Newton (Lipson et al., 2010). Refractive index or index of refraction “n” describes how radiation or light travels through a material and shown in equation 3-1 (Hecht, 2002). In this equation, n is the refractive index of the material, c is the speed of light in a vacuum and υ is the phase velocity of light in the chosen medium (Hecht, 2002).

$$n = \frac{c}{v}$$

Equation 3-1. Refractive index or index or refraction

With the concept of refractive index having been presented, the concept of Snell’s Law can be explored. Snell’s Law was presented in literature by Willebrord Snell in 1621; while others including Thomas Hariot, Walter Warner, and Sir Thomas Aylesbury were independently working on the same physical phenomena, Snell is historically credited with the discovery (Shirley, 1951). Before we present Snell’s Law, a companion concept is the critical angle. In simple terms, if we have two materials with varying refractive indices, the critical angle is the angle which anything less results in total internal reflection.

$$n_1 \sin \theta_1 = n_2 \sin \theta_2$$

Equation 3-2. Snell's Law

An illustration of Snell's law, critical angle, and total internal reflection is shown in Figure 3-6 where n_1 represents the center of an optical fiber (core) and n_2 represents the cladding of a fiber.

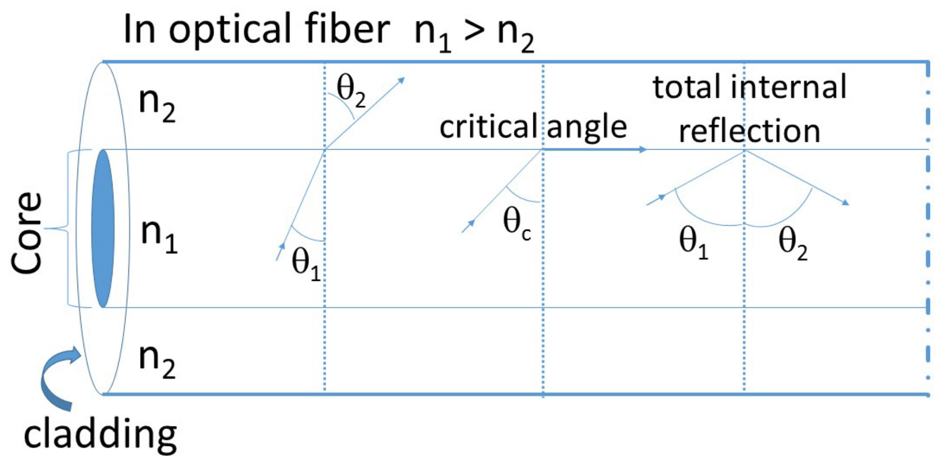

Figure 3-6. Optical fiber and basic concepts

As a sub-class of sensors that span both physical and chemical sensors we have the fiber optic sensor. This type of sensor plays a significant role in the oil and gas arena and due to ability to sense passively without endpoint electronics is particularly useful for the hostile downhole environment. As an example, Schlumberger Limited has developed fiber optic sensors for downhole temperature pressure measurements for application in oil wells with possible applications in gas wells. This technology known as a Distributed Temperature Systems takes advantage of fact that fiber optic sensors often have what amounts to the equivalent of thousands of distributed sensors along the fiber's length. A fiber Bragg grating (fig.

3-7) can be a key component of a modern distributed fiber optic sensor system (Hill and Meltz, 1997), (Kersey and Berkoff, 1992).

In short, a Bragg grating is a fabricated periodic pattern of differing indices of refraction to create a desired effect; sometimes holographic methods are used to impose this pattern (Meltz et al., 1989) (Fig. 3-8). The Bragg grating is capable of measuring: vibrational, temperature, and pressure information which is relayed in real-time along the entire depth of the production well. This enables the measurement of reservoir performance, and to help judge well completion integrity. Many of these types of sensors use Bragg grating technology the can even function simultaneously as a temperature and pressure sensor as explained in research by Annamdas (Annamdas and Annamdas, 2010).

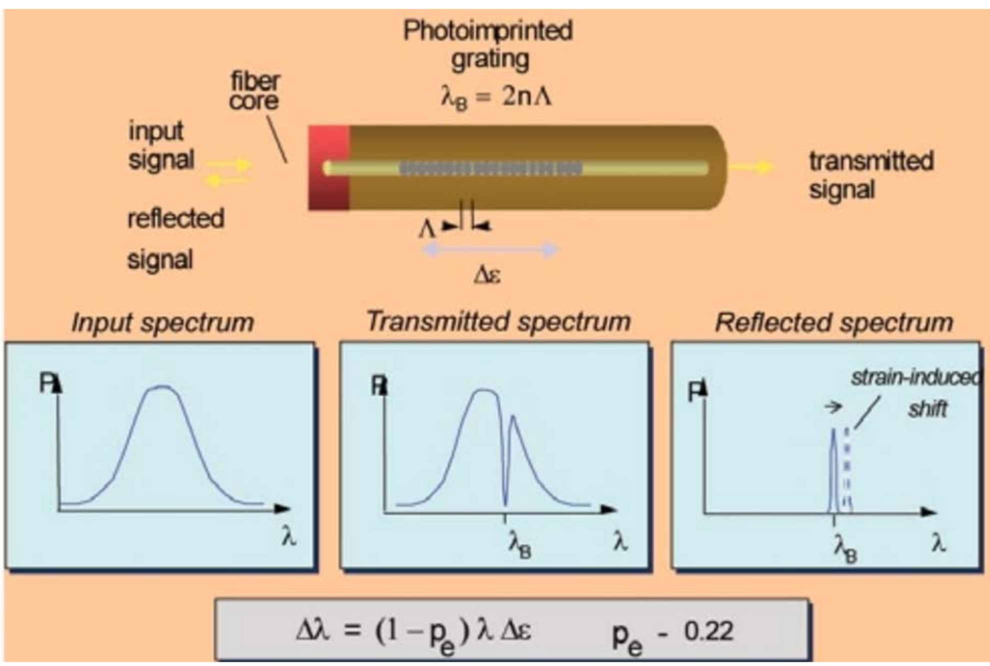

Fig. 3-7. Fiber optic Brag grating in action

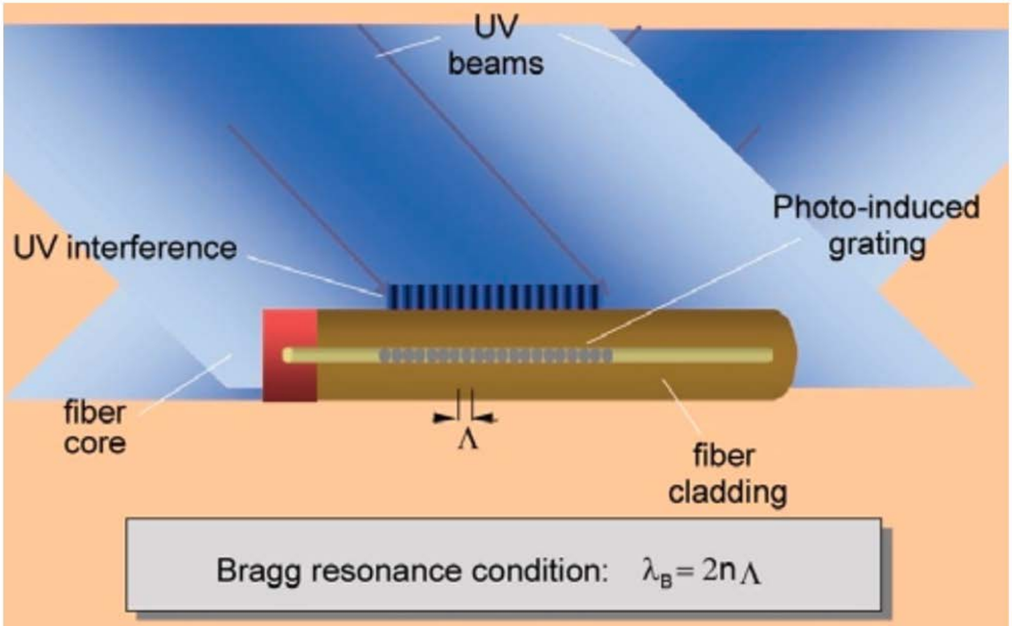

Fig. 3-8. Fiber optic Bragg grating – “burning” a pattern

A specific implementation of Bragg technology was studied by Keul et al. (Keul et al., 2005) and again by Hornby et al. (Hornby et al., 2005). These studies deployed permeant “in-well” fiber optic sensors capable of measuring microseismic events which proved useful for understanding reservoir behavior when contrasted with surface seismic readings (Keul et al., 2005), (Hornby et al., 2005). Before this technology was tested by Keul et al., other fiber optic seismic sensor systems (lacking Bragg technology) proved to be bulky, and unfit for “in-well” deployment (Gardner and Garrett, 1988).

3.2.6 Hydrologic Fracturing Sensor Touchpoints

Hydrologic fracturing operations offer a significant opportunity for smart sensor technology. The fracking process is many decades old and thus, from a mechanical and chemical standpoint is well understood. In order to show how sensors can align with fracking operations, we now highlight the various categories of sensors for surface hydro fracking operations

- Well and Drilling Sensors
- Surface activity sensors
- Asset tracking
- Atmospheric Sensors
- Aquatic Sensors
- Seismic and Ground Condition Sensors

Well and Drilling Sensors are used to monitor the progress of well completion. They are considered to be "down hole" sensors that must in some cases survive unique conditions as well as limitations of RF (wireless) underground. Some explorations companies use fiber optics as both the sensor and the physical medium for transmitting telemetry information

Surface Activity and Storage Sensors in the hydro fracking arena should focus on the movement of equipment and movement of fracking vehicles such as water trucks. How does all this movement impact the environment through accelerated erosion and noise? In addition, this project has deployed EM Field sensors on the battery where produced hydrocarbons are stored and susceptible to lightning strikes and charge buildup resulting in fires.

Asset Tracking and automation with sensors is a critical area for project management of these sites. Unfortunately, most hydro fracking exploration companies fail to use automated site asset tracking with sensor systems. By leveraging such a system, equipment and supplies could be tagged with low-cost RFID tags. By using a system with multiple readers and landmark references (fixed know RFID points) in combination with Probabilistic Kalman Filtering, precision and accuracy can be achieved to within centimeters in 3 dimensions (Bekkali et al., 2007; Nazari Shirehjini and Shirmohammadi, 2009). The benefits of such a sensor system to the owner operator of hydro fracking sites will discussed in chapter 5.

Atmospheric Sensors are of particular importance to PXD and a case study of such sensors along with results will be presented in subsequent chapter 4. DAQFactory a controls and simulation environment in combination with the Python scripting language is used to show decision tree algorithm enabled sensors in action. PXD currently has lightning sensors deployed at the battery that were part of this research project.

Aquatic Sensors can be used to monitor both underground water sources including both wells and aquifers. In addition, holding ponds and water discharged directly into waterways can also be measured for radioactivity and chemical concentration.

Seismic and Ground Condition Sensors can be used to show the relationship between hydro fracking activities and seismic activity adjacent to hydro fracking sites. Several scholarly studies and even the hydro fracking industry itself has shown that there is a correlation between minor seismic activates and hydro fracking operations.

3.3 Examples of Prior Activities in Risk and Optimization at Fracking Batteries

3.3.1 Risk

The Project Management Body of Knowledge (PMBOK) describes risk in this way: '*An uncertain event or condition, that if it occurs, has a positive or negative effect on a project's objective.*' (Institute, 2008) The focus here is on the term uncertain event; it is unknown if this event will or won't happen, and maybe even when it could happen. With this said, a project manager is only concerned with events that will impact the project. (Weaver, 2008)

In order to gain a foundational understanding of risk, it is critical to understand two hand-in-glove pairs of terms: uncertainty vs. variability along with accuracy vs. precision. In particular, uncertainty refers to a situation that might occur, where variability is an inherent in almost every project or process. The goal is to minimize unexplained variability to achieve acceptable outcomes (Weaver, 2008). Precision refers to the repeatability of a process while accuracy refers to the degree of "correctness" of a process. You must have both precision and accuracy to shoot consistent 3-point shots in basketball.

3.3.2 Decision Trees

Given certain conditions or parameters, a sensor system will be able to make decisions to for instance: open or close valves, turn on or off pumps, sound alarms, or simply cease an operation. While decision trees are part of this dissertation, they are by no means the focus of this research. Rather, decision trees are one of many tools that can be used as a vehicle for automated sensor systems. There is direct interplay with decision trees and the implementation of IPLs. Should mitigation be activated or not?

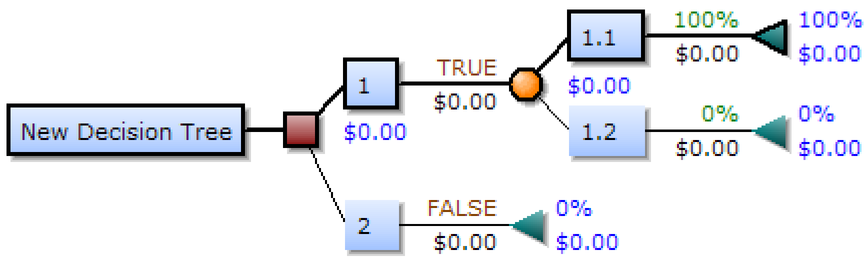

Figure 3-8. Example Decision Tree

3.4 Summary

Fiberglass hydrocarbon storage tanks are ubiquitous in the fracking industry; they are relatively cheap and unfortunately flammable. Sensors can play critical role in mitigating the impacts from lightning strikes on hydrocarbon storage tanks. The diversity of sensors coupled with the presented touch points for hydro fracking operations hold promise for additional integration in the future.

Chapter 4: Research Methodology

First, we review the research questions presented in Chapter 2, cite their importance and present a methodology to discover answers to these research questions. Some fundamental questions to have in mind are: why are methodologies used by others on similar problems relevant to our problem? Did others have flaws in their methodologies? What makes our approach valid?

4.1 Appropriate Methodology for Addressing the Research Questions

In sections 2.2 and 2.3 we presented research questions and also presented implications for the industry if sound answers are discovered. In section 2.2 we presented the research questions as re-written here:

1.) As fracking continues throughout the United States (and world), data is showing that the prevalence of lightning in fracking areas will increase dramatically. Therefore the risk of an explosion – with accompanying financial and environmental consequences – is expected to increase dramatically as well. Is there a way to use sensors and modeling to help minimize the financial and environmental losses and issues? If so, could it be automated?

In order to answer this fundamental question, a number of associated questions must be answered, including:

2.) Develop the driving equations of the intersecting items, such as:

- probability of lightning strikes,
- cost of an environmental incident (pollutant dependent)
- well production estimation (temporal dependent)
- cost to incumbent organization for an incident (cost to fracking company)

3.) What are the border implications for sensors and lightning detection beyond hydro fracking hydrocarbon storage?

Let us now consider the following to aid our analysis:

- o Are methodologies used by others on similar problems relevant to our problem?
- o Did others have flaws in their methodologies?
- o What makes our approach valid?

4.1.1 Relevant methodologies used by others

The problem of lightning in open-air industrial settings is a well-known problem (Chang and Lin, 2006). Operation supervisors at these sites resort to weather forecasts and rules of thumb to change operational posture or even suspend operations. For purposes of insurance and indemnification, most operators use NOAA lightning guidelines[12].

The onsite managers are often burdened with the responsibility of making a real-time decision with financial considerations such as: equipment might be lost, environmental damage may occur, or lives might be lost (due to lightning strikes).

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[12] http://www.lightningsafety.noaa.gov/resources/large_venue.pdf

Often SOPs implement broad OPCONs (Operational Condition) that may not account for all risk or consequences in real-time operations.

Before the particular methodologies used by others is presented, the concepts of Time of Arrival (TOA) and Time of Group Arrival (TOGA) shall be discussed. TOA is sometimes called Time of Flight (TOF); as such this is the amount of time it takes for a signal to travel from the transmitter (source) to the receiver (detector). As an expansion on TOA, TOGA is the fusion of more than one TOA contribution to produce more enriched and accurate data; geolocation is more precise as a general consequence.

An organization called Blitzortung has developed a community-based platform for Time-of-Arrival lightning detection. Unassembled sensors kits for purchase are currently only a modest 200 Euros (Fig 4-1) (Wanke, 2014).

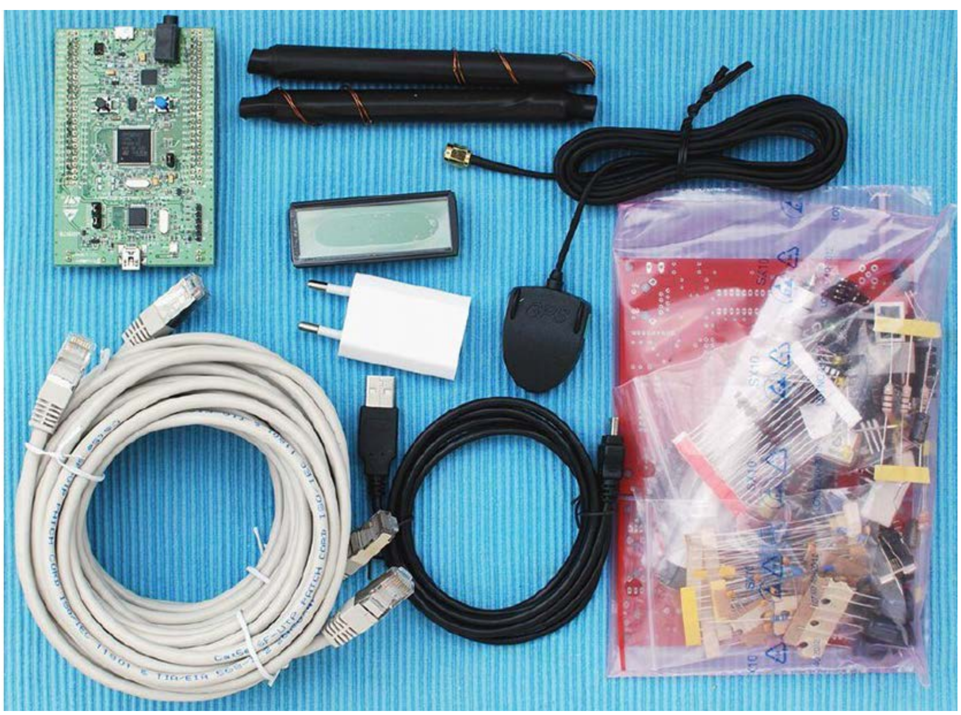

Fig. 4-1. Community-based platform for Time-of-Arrival lightning detection

This project is setting out to form a low-cost solution to world-wide location solutions. The accuracy and precision (see Fig 5-16), is based on the spacing of each station; typically 50 – 250 Km. Sensors detect lightning strikes, then transmit the occurrence of an electromagnetic pulse to central servers for information fusion. However any data supplied to the project can only be used for non-commercial purposes. Furthermore, since these are kits, Blitzortung says that any modifications to the kit including the amplifier will invalidate you contribution to the community TOA calculations. In addition, the kit is susceptible to any electromagnetic interference from: power supplies, computers, fluorescent lamps, and Televisions. In some cases Blitzortung says that this has resulted in invalid data being transmitted. The information from one station is not enough to compute the position of a lightning strike; a minimum of 4 stations is required **(Wanke, 2014)**.

Another organization called the World Wide Lightning Location Network (WWLLN) determines the location of lightning events around the globe in real-time with a focus on stroke power (Hutchins et al., 2012). This system operates with 1 km errors for location information and has detection efficiency of >90%; in addition, the system can provide an estimation discharge amplitude and polarity (Jacobson et al., 2006). The system detects VLF electromagnetic radiation and leverages TOA and TOGA much like the Blitzortung system (Abreu et al., 2010).

The National Oceanic and Atmospheric Administration (NOAA) takes a different approach to detecting lightning strikes[13]. In cooperation with the U.S. Air Force 14th Weather Squadron located in Ashville, NC. Through this squadron, the Air Force works with the United States National Climatic Data Center (NCDC)[14]; a branch of NOAA. Currently, cloud-to-ground and intra-cloud lightning flashes are detected by a network of 100 ground stations across the country. The flashes are mapped in real-time by the National Lightning Detection Network (NLDN) developed by the New Mexico Institute of Mining and Technology (NMIMT). Users have access to real-time data (Government or Military only) and the public has access to processed data of over 160 Million flashes since 1986 (raw data is not available for public or commercial use)[15] The same NSSL site (as footnoted below) discussed an experimental satellite that observes flashes in tropical regions, but is unable to differentiate between cloud-cloud and cloud-ground lightning.

4.1.2 Flaws in methodologies used by others

As outlined in section 4.1.1, there are 2 primary methodologies used by others for the detection of lightning events. They were VLF (Radio Frequency) signals and TOA techniques, and ground based photonic detectors. Both of these general techniques are not predictive in nature; they are observing past events. In addition, none of the systems including the community sourced effort by Blitzortung

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[13] http://www.ncdc.noaa.gov/data-access/severe-weather/lightning-products-and-services

[14] http://www.ncdc.noaa.gov/

[15] https://www.nssl.noaa.gov/education/svrwx101/lightning/detection/

will permit the **real-time** sharing of raw data for commercial or public consumption. While some of these systems as described had detection accuracies of 1 Km and efficiencies of >90%, without real-time access to raw data, this is little use to the industrial practitioner or automated system in assessing lightening risk **hear and now.**

4.1.3 Deployed methodology - Lightning Anticipation Technology

By deploying a system that detects atmospheric charge buildup, the test system is able to predict a lightning strike. Lightning is caused by electrical charge separation in the atmosphere. The intensity of this charge separation can be determined by measuring the electric field, which is accomplished with an Electric Field Meter (EFM) Thus, monitoring of the electric field can warn people of a potentially dangerous situation, before the first lightning occurs. Following is a description of the process.

On a clear day, when the atmosphere is clear of storm clouds, the primary source of electric charge creating an electric field on the surface of the earth is the ionosphere. This can be thought of as a large dome-shaped electrode high above the earth, which produces positive charges which contrast to the relatively negatively charged earth. This scenario creates what is termed a "fair weather" electric field due to the positive charge overhead. When this "fair" field is measured by the EFM, it can be seen to produce an output of from 50 to about 200 Volts per meter ("V/m"). This value varies, depending upon conditions in the atmosphere, and is also altered by "local effects". Such effects are caused by anything which can carry electrical charge, including but not limited to atmospheric space charge, dust, smoke, litter, etc. Usually, though, the field stays between -50 and -200 V/m during fair or non-stormy weather.

When thunderclouds form, however, processes within their vicinity cause the formation of negative electric charges (the opposite of the ionosphere) at the cloud base. As the charge builds, it creates a "foul weather" electric field which grows and then begins to cancel out the "fair weather" field. As it builds further, it becomes many times greater than the fair weather field. It is this "foul weather" electric field which intensifies to the point that the air can no longer insulate the opposite charges. Finally, the positive and negative charges are drawn together suddenly via any convenient "weak spot" which occurs in the atmosphere. This is the energetic discharge we call lightning.

Foul weather electric fields can reach values of well over 10,000 volts per meter at the ground during a storm.

It is the separation of positive and negative electric charges into large groups which creates the lightning hazard. These groups, of opposite polarity, are naturally attracted to each other but held apart by the atmosphere's insulating properties. As these groups grow during the formation of a storm, the force of their attraction can exceed the atmosphere's ability to keep them separated. Lightning is the sudden, intense electrical recombination of these groups which occurs when this point is reached. The local electric field varies in proportion to the strength of these groups and their distance from the measuring device, so its measurement gives an idea as to the likelihood of lightning occurring. A strong electric field indicates that the situation is conducive to the formation of lightning.

This is an over-simplified explanation of what is actually a very complex process. It is clear, however, that determining the local electric field can play a major role in determining the likelihood of lightning occurring in a particular area of the earth.

Military (U.S. Navy NAVSEA) and other government agencies (NOAA) have determined that electric fields above 2000 Volts per meter create the greatest lightning threat. Many operations centers have requirements to cease and secure certain operations when the electric field reaches this number in an effort to reduce damage or injuries caused by lightning. A high electric field reading does not ensure that lightning will occur, but only that conditions are conducive to its occurring.

Experiments have shown that due to the relatively large size of thunderclouds, the electric field does not show tremendous variation over short distances. If the electric field has reached a value of 2000 Volts per meter at one location (a dangerous level), it will be reasonable to assume that the level is dangerous for several miles, at least, in any direction. Likewise, if the level is below 500 Volts per meter (a relatively non-hazardous level), it can be assumed that the hazard is low for at least several miles.

Although predicting an actual lightning strike is difficult if not impossible no matter what technique is used, monitoring the local electric field along with some interpretation and experience can be one of the best ways to determine how likely it is for lightning to strike an area.

The electric field variations during a typical thunderstorm are shown in Figure 1. Before 2240 hours, the field is low and positive (fair weather polarity), but small "bumps" indicate distant lightning. The local threat is probably still low at this time. At 2240, the field "crosses zero", and begins to climb. This is when one should prepare to take cover. Around 2250 the field exceeds 2kV/m, and the threat should be considered serious. The small "bumps" due to the distant lightning are often not present, particularly if the buildup is directly overhead and lightning has not yet begun. What is important here is the average level of the field.

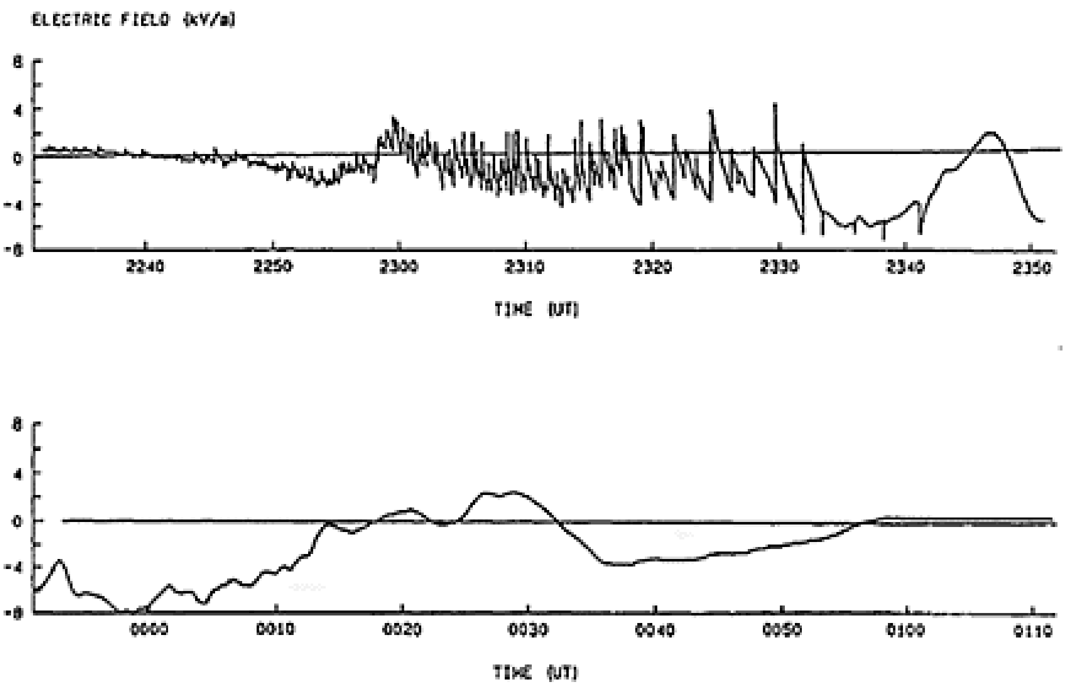

Figure 4-2. Electric field measurements during a typical lightning storm (from Mission Instruments).

As a storm builds, the physical arrangement of the charged bodies (clouds) combined with the various effects they have on the local atmosphere can create a variety of electric field build-up patterns. Also, when lightning strikes, either between the cloud charge pockets or between these pockets and the earth, it will cause a large change in the electric field as seen by a EFM. These changes, often fast-occurring and short-lived, can take the field back and forth between fair and foul polarities many times during a storm as can be seen between 2300 and 2330. No lightning events occur after about 2341. This is typical of end-of-storm behavior, although a significant threat still exists. Lightning often does typically occur during this phase of the storm.

4.2 Instrumentation and Communications for In-Field Research

Large scale hydraulic fracturing sites with inherent exposure to potentially catastrophic events, lack sensor integration with decision algorithms. This is particularly true for catastrophic atmospheric events such as charge induction, and direct lightning strikes.

Field instruments supply raw data that must be analyzed in the context of risk in order to make informed project decisions at a particular site. By using equations presented in Chapter 2 and 3 for application in Chapter 5 I will lay the ground work for an analytic tool that will provide planners and managers with unique insight into the lightning threat and their operations.

4.3 Unique attributes of the Field Test Location

Large scale industrial operations will be the immediate beneficiaries of this research. As such, the chosen facility was hosted by Pioneer Natural Resources (PXD) at a functioning hydro fracking site. The specific site will be outline in greater detail in Chapter 5. For relevance to this section, the specific reason for choosing this particular battery for our test site involved access and general logistics. The chosen site has easy access from a main access road and houses the right kind of battery tanks for my tests (fiberglass tanks). Realizing that producing meaningful results will require a diversity of tanks.

4.4 Candidate Analysis Tools for Data Interpretation

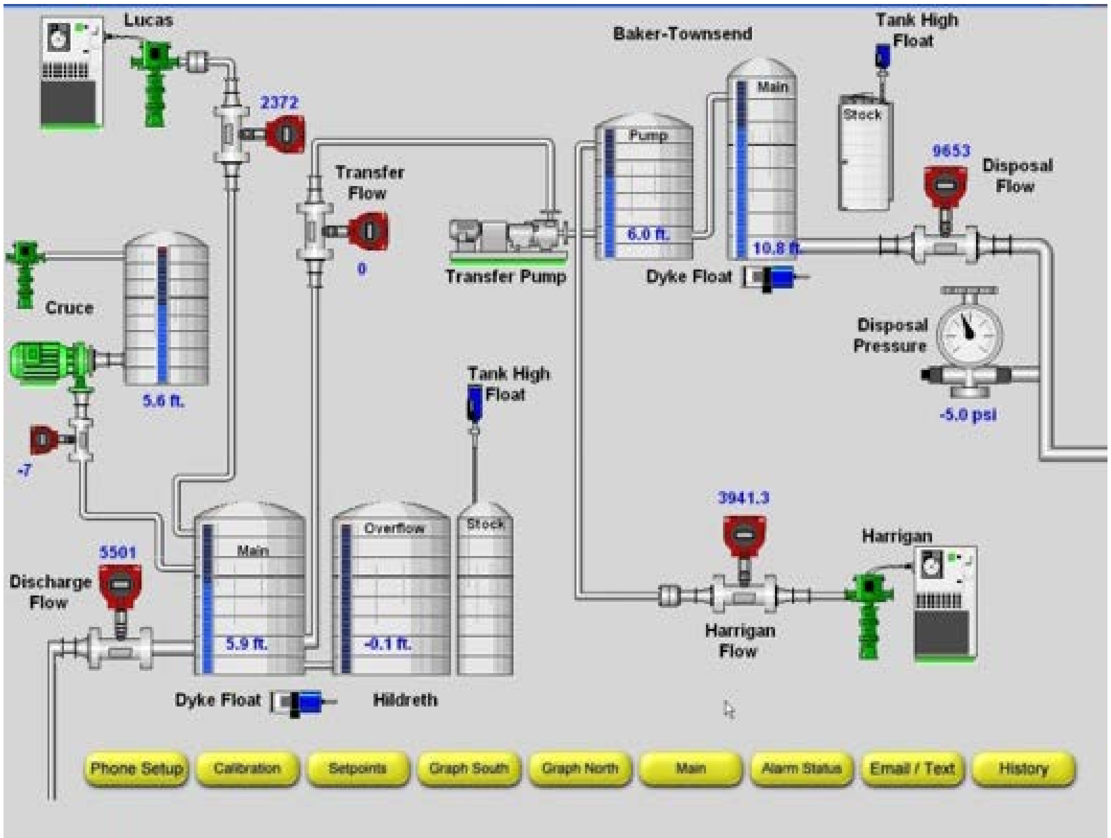

Fig. 4-3. DAQFactory model and control interface

Given enough detailed information about the system of systems that comprises the hydro fracking operation, a complete model and interface can be developed (Fig. 4-3). However, this is a multi-million dollar effort that will require years of onsite proprietary access to PXD operations and equipment across diverse sites.

Notwithstanding these limitations, very important foundational steps can be taken toward providing value to hydro fracking operations. By using basic simulation tools such as Monte Carlo, the threat of lightning and a potential mitigation strategy can be quantified.

4.5 Operational system for lightning and charge situational awareness

As was explained in section 4.1.3, this research project deployed an atmospheric charge solution for lightning detection. To reiterate, this technology differs greatly from the VHF (Radio Frequency) and photonic detectors used by others including NOAA as outlined in section 4.1.

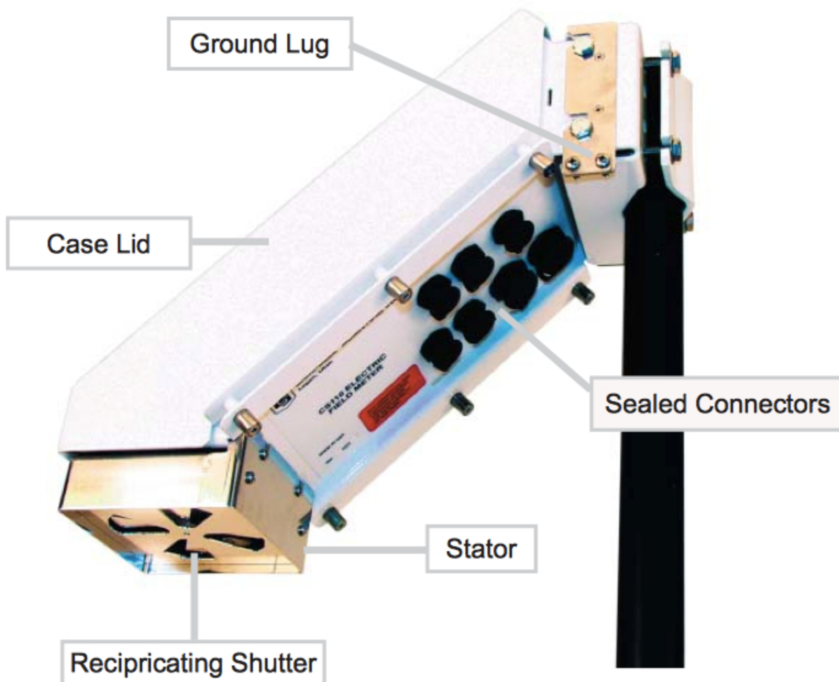

Fig. 4-4. Campbell Scientific (CS110) Electric Field Meter

By deploying a proven electric field meter designed by Campbell Scientific (CS110), for the application of measuring atmospheric charge to predict lightning strikes, performance variables can be minimized. Since the CS110 sensor system is a proven technology, performance has been benchmarked by various organizations including NAVSEA (U.S. Navy), NASA, and NOAA.

These organizations have developed thresholds for lightning warning hazards with a device such as the CS110. NASA (in collaboration with NOAA) considers a charge reading on the CS110 ABS (1000 V/m) to represent a hazard within its Launch Pad Lightening Warning System (LPLWS). The U.S. Navy takes a more conservative approach and considers a charge reading on the CS110 above ABS (2000 V/m)[16]

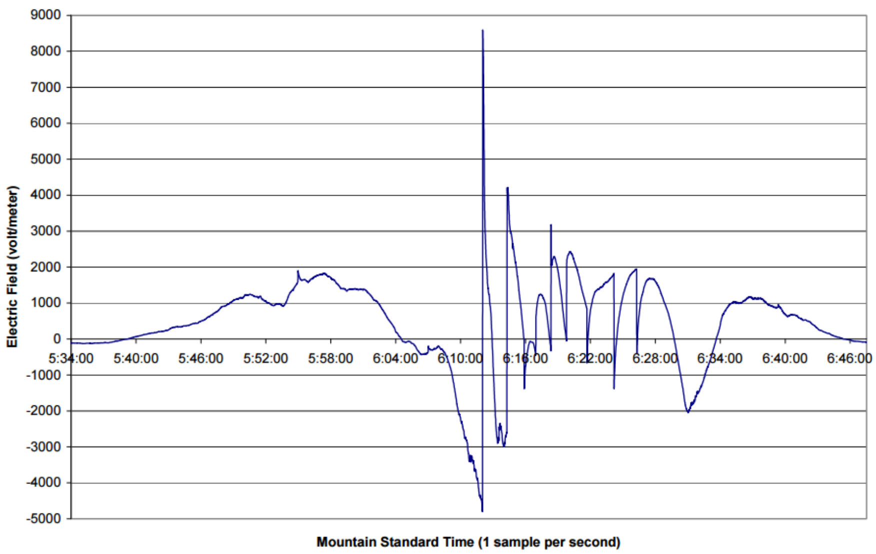

Fig. 4-4. Electric Field vs. time during an electromagnetic storm (CS110)

In addition to Electric Field monitoring by the CS110, a custom built solution was deployed to monitor the electrostatic buildup on fiberglass tanks as this has been shown to be a pathway for tanks fires by other researchers (Chang and Lin, 2006). Thus, monitoring the static charge buildup on fiberglass tanks is a facet of our approach to answer the research questions outlined in chapter 2 and again at the outset of this chapter.

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[16] ABS in this case represents absolute value. Obviously, the smaller the number, the easer a system may trigger an alarm.

The deployed tank charge monitoring solution will be described at length in Chapter 5, however here we highlight its value as a methodology toward answering our research objectives. By measuring the electrical charge buildup and non-conductive fiberglass tanks, there exists another modality for evaluating the potential for electrical discharge; in this case on a much smaller scale than a direct lightning strike namely, static discharge. The results can be similar as a static discharge cans till trigger a fire or in some cases depending on volatile contaminants, and explosion (see Table 3-2). Produced hydrocarbons and are known to be a mix of many components and therefore do not only exhibit the moderate volatility associate with crude oil.

4.6 Data Acquisition via Remote Telemetry – Data Fusion

In order to transform data into intelligence, it must be fused with other parameters including tank charge sensors and even humidity conditions in the atmosphere. Intelligence is a product of data fusion and is the basis upon which an operator or planner can take action.

Data fusion can be loosely defined as the exploitation of information from multiple data sources (sensors) to estimate or infer a set of desired attributes about a set of target entities (Hall and Llinas, 1997). The sensors can be similar in nature (e.g., temperature sensors) or quite diverse (i.e., multi-modal), such as a combination of temperature sensors, pressure sensors, humidity sensors, cameras, etc. Data collected usually overlap in time and/or space, or are complementary in nature. A natural question to ask is why anyone should care about such fusion of data from multiple sources. A short yet quite general answer is that it provides the following advantages over a single data source scenario: 1) wider spatial/temporal coverage, 2) improved robustness/fault tolerance, and 3) improved estimation of relevant information from raw data. Fig. 4-5 illustrates the basic idea of fusing data from multiple sensors.

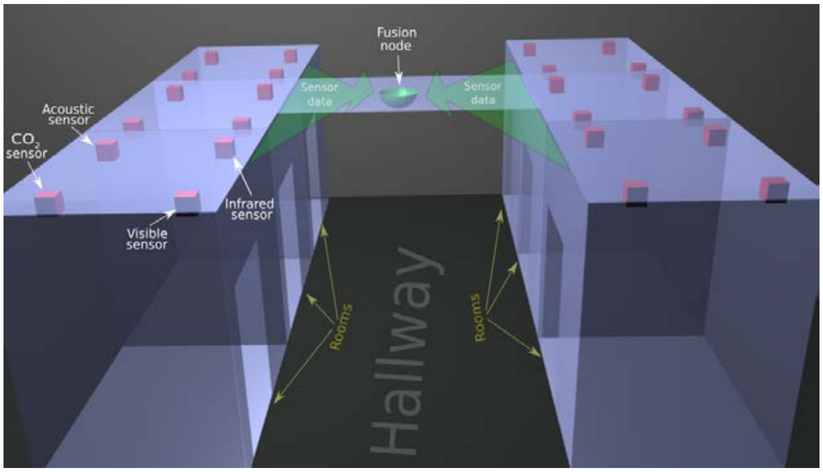

Fig. 4-5. A Sensor Fusion Scenario Inside a Building

The figure portrays a scenario of a typical office space with a hallway and multiple rooms on each side. Four different sensors are mounted on the ceiling in each room: 1) a carbon-dioxide sensor, 2) an acoustic sensor, 3) an infrared sensor, and 4) a visible camera. Data from each of these sensors in each room are combined by a data fusion node shown mounted in the ceiling over the hallway. This node combines the data from all the sensors and produces high-level knowledge about this space that can be used to automatically control the indoor environment or by a building manager to assess the operational efficiency of the lightning system and HVAC (heating, ventilation, and air conditioning) in the facility.

4.6.1 Wider Spatial/Temporal Coverage

Wider coverage is obtained by aggregating data from individual sensors with each sensor having a relatively limited coverage. For example, suppose a building is monitored through security cameras which are the data sources in this case. One camera may be able to only see the main entrance area but not the rest of the building. So, with this camera alone, one would not have any information about the status of the other areas in the building. However, if a second camera is placed on the opposite corner and the data from both the cameras are combined, one can now monitor the entrance area as well as the opposite end of the building. Adding more cameras will provide surveillance coverage for more and more areas by aggregating or fusing the data from each camera. Thus, fusion of data from multiple sensors can provide wider spatial coverage. The same can be true in terms of temporal coverage as well. A visible camera may only work during the day when there is adequate light available, but will likely not work at night when the building is dark. If an infrared camera with the ability to see during the night is also deployed, data from these two types of cameras can be combined to gain wider temporal coverage. Such spatial and temporal monitoring without a coverage gap is critical in many applications, and data fusion is a key enabler behind such capabilities.

4.6.2 Better Robustness/Fault Tolerance

Having more than one source of data (i.e., redundant sources) can provide better robustness or fault tolerance. If a small subset of the sensors happens to fail or malfunction, the data from the other sensors can fill the gap and maintain the flow of critical data. Care needs to be taken, however, to differentiate data streams obtained from malfunctioning sensors from data provided by properly functioning sensors. Otherwise, completely inappropriate decisions may be made in a given situation. To help identify this, simple and often effective technique is a consensus-based approach in which the majority of compatible data are assumed to be the standard and any disagreements from this standard are assumed to be problematic. The underlying assumption is that failures are rare and that most of the sensors are not faulty.

4.6.3 Better Estimation of Information from Data

Having a multitude of sensors measuring raw target parameters creates the possibility of inferring a much higher level of information about the target than is usually possible with a single sensor. However, it is important that raw data from multiple sensors are not highly correlated. The more diverse the data, the better the estimation will be.

For example, suppose we are trying to extract the three-dimensional shape of an object from three different cameras. If one camera each is dedicated to capturing the front view, the rear view, and the top view, then combining the images from all three cameras can provide a fairly decent idea about the shape of the object. This is because the images from the three cameras were taken from three very different viewpoints and hence they were *diverse* or fairly *uncorrelated*. However, if all three cameras are placed near each other in front of the object, there is no good way to infer the shape at the top or the back side of the object. In this case, the data from the multiple sensors (cameras) are very similar and not diverse enough to provide more inference than can be determined from a single sensor. Such data are said to be highly *correlated.* So, if a set of sensors is deployed to produce data that are significantly *uncorrelated*, then data fusion across those sensors can greatly improve estimates of the target's attributes of interest.

Various research efforts have shown how using data fusion helps improve estimating target parameters. For example, Strelow et al. (Strelow and Singh, 2002) fused optical, as well as inertial parameters, then measurements were used to obtain optimal motion estimates of targets. Also, research by Veth et al. (Veth and Raquet, 2007) has demonstrated the value of integrating optical and inertial measurement units for navigation.

4.6.4 Technical Details

Sensor fusion can be broadly classified into two categories: 1) *homogeneous* and 2) *heterogeneous*. In the first case, the sensors that produce data to be fused are identical in terms of sensing capabilities and output properties, whereas in the second case, the system consists of diverse kinds of sensors, such as acoustic sensors, imaging sensors, temperature sensors, pressure sensors, etc. In general, fusion across a set of homogeneous sensors is easier than fusion of data from heterogeneous sensors, primarily because data alignment, one of the most fundamental steps in data fusion, which is easier in the case of homogeneous sensors.

The data fusion process can also be categorized into three broad classes based on the amount of pre-processing done on the raw data before fusing them: 1) low-level fusion, 2) feature (intermediate)-level fusion, and 3) decision (high)-level fusion.

4.6.5 Low-Level Fusion

In low-level fusion, raw data from the sensors are fed to the fusion engine with minimal pre-processing and the engine extracts all high-level information. The volume of data transferred between a data source and the fusion node is relatively high because the sensors can collect quite a large volume of raw data to be fused. This may make this paradigm infeasible where the communication bandwidth is low Fig. 4-6, illustrates this fusion paradigm.

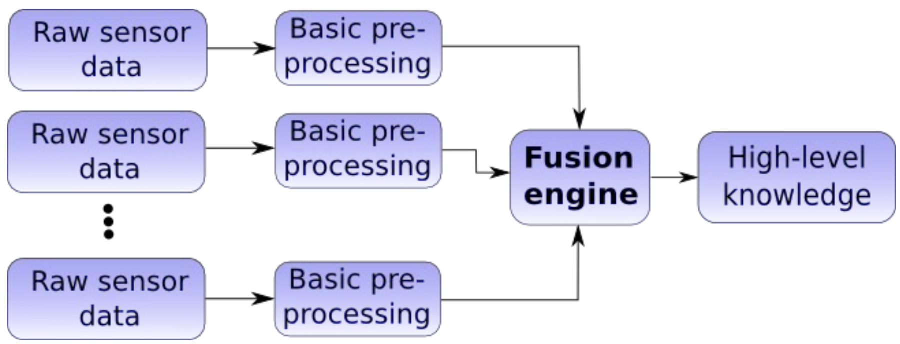

Fig. 4-6. Low-Level Data Fusion Scheme

4.6.6 Feature-Level Fusion

This scenario can be thought of as an intermediate-level data fusion scheme. Each sensor platform has sufficient computational capability to identify interesting properties corresponding to the desired targets and extract a set of relevant features to be input to the fusion engine. It then extracts high-level information by combining these features from the individual sensors; Fig. 4-7 illustrates this fusion paradigm. The paradigm is based on the assumption that it is possible to identify and segment the targets in each sensor data on its own without any input from any other sensor. The extracted features generally require a significantly smaller data volume than that of the raw sensor data. Because the only data transferred between a sensor node and the fusion engine are the extracted features, the communication bandwidth required under this fusion scheme is significantly less than what is required in the case of low-level fusion.

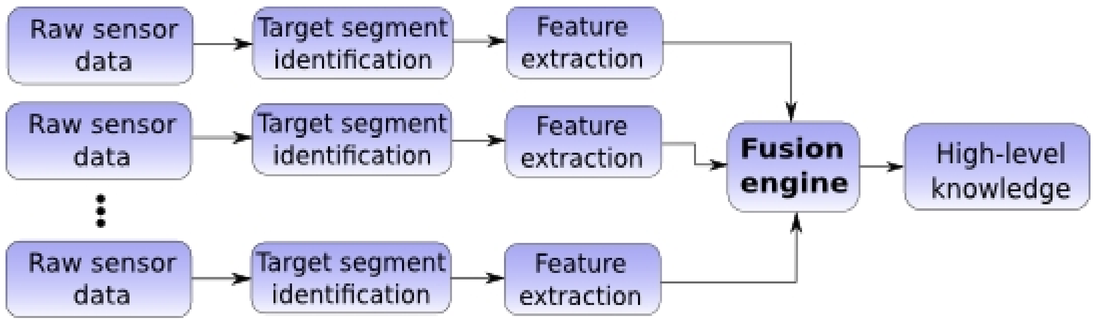

Fig. 4-7. Feature-Level Fusion Scheme

4.6.7 Decision-Level Fusion

In this case, each of the data sources have sufficient onboard computing capability to process the raw sensor data to generate higher-level information with a more compact representation than the raw data. It is this higher-level information that the sensor nodes feed to the fusion engine. As a result the communication bandwidth requirements are more modest than in the case of low-level fusion. Fig. 4-8. illustrates the concept of decision level data fusion.

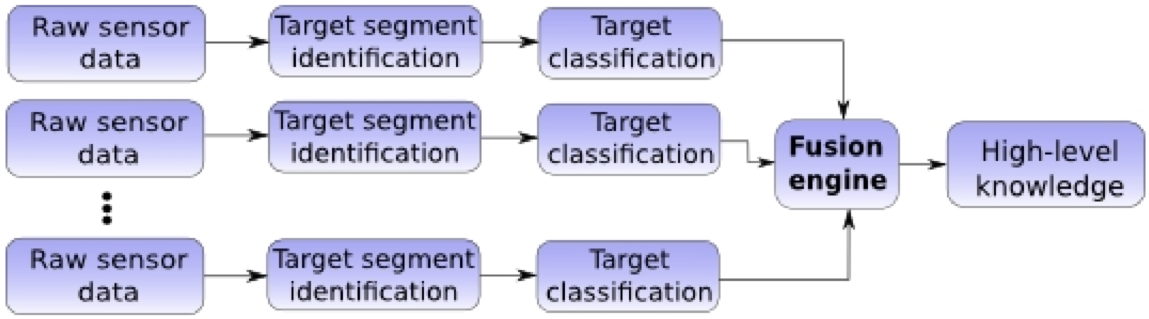

Fig. 4-8. Decision-Level Fusion Scheme

As an example, suppose one wanted to count the number of people in a building where each office is equipped with a camera to capture images at pre-defined time intervals. For this scenario, assume that image processing algorithms have been developed to extract the number of people that appear in a captured image. In a low-level fusion scenario, the camera in each room will send the raw image pixel data to a fusion engine which will then process each image to find the number of people in each office, and subsequently add the numbers from each office to report the total number of people in all the offices combined. Because each camera transmits the raw image, the bandwidth requirement is quite high.

In the case of feature-level fusion, each sensor may analyze its image to determine the segments that show change from a reference image, such as an empty room. Then the changes would likely correspond to human occupants. However, a change may also correspond to an item in the room that has been moved since the reference image was captured, such as a chair. The sensor in this paradigm does not differentiate humans from non-humans. It simply identifies the image segments corresponding to such changes and extracts relevant features, such as the area, shapes, and locations in the image of these segments. It then sends these features to the fusion node which combines them to produce the high-level knowledge about the environment.

In contrast, with a high-level fusion scenario, each camera system will locally run all the algorithms necessary to extract the accurate count of people in the respective room by fully analyzing the captured raw image and only send this number (a single integer) to the fusion engine, which will add up the numbers sent by each camera to output the final result. Obviously, the bandwidth requirement in this case for the transfer of high-level information (a single number) by each sensor to the fusion engine is significantly lower than that in the previous cases where the whole image or the features had to be transferred. But this reduction in bandwidth comes at the expense of each camera system requiring enough computational power to perform complete image analysis.

4.6.8 Distributed versus Centralized Fusion

Traditionally, a centralized architecture has been common in data-fusion systems. In such a system, there is a single fusion processing node, and all the sensors send their data to this node. The fusion node is responsible for all aspects of data merging and extraction of high level information; Fig. 4-9. illustrates a centralized fusion system (Esteban et al., 2005). This approach is algorithmically simple to implement but requires significant communication bandwidth because every sensor needs to send the entire output to the fusion node. A major drawback of this approach is its susceptibility to a single point of failure. If the fusion node fails, the entire system ceases operation.

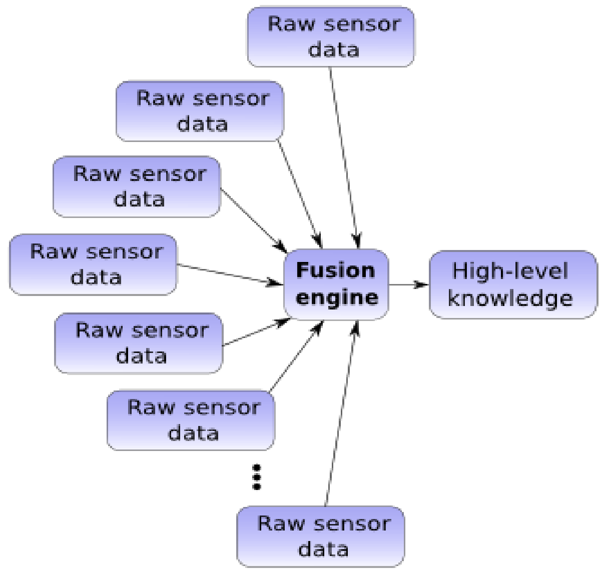

Fig. 4-9. Centralized Fusion Architecture

However, a data-fusion system does not necessarily need to have a centralized architecture. The fusion task can be performed in a distributed manner. An incremental step toward distributed fusion from a centralized framework is an architecture in which the overall fusion task can be divided into smaller subtasks that are performed by separate fusion sub-engines. The output of each of these sub-engines can then be merged at a master fusion node to produce the final fused output. This is a bi-level hierarchical fusion architecture. The obvious generalization is a multi-level hierarchy. Hierarchical fusion architectures can be broadly classified into two categories—one with feedback and the other without feedback among the fusion nodes. Fig. 4-10 illustrates the concept of hierarchical fusion. **Error! Reference source not found.** 4-10(a) shows an architecture without feedback, and Fig. 4-10(b) shows one with feedback.

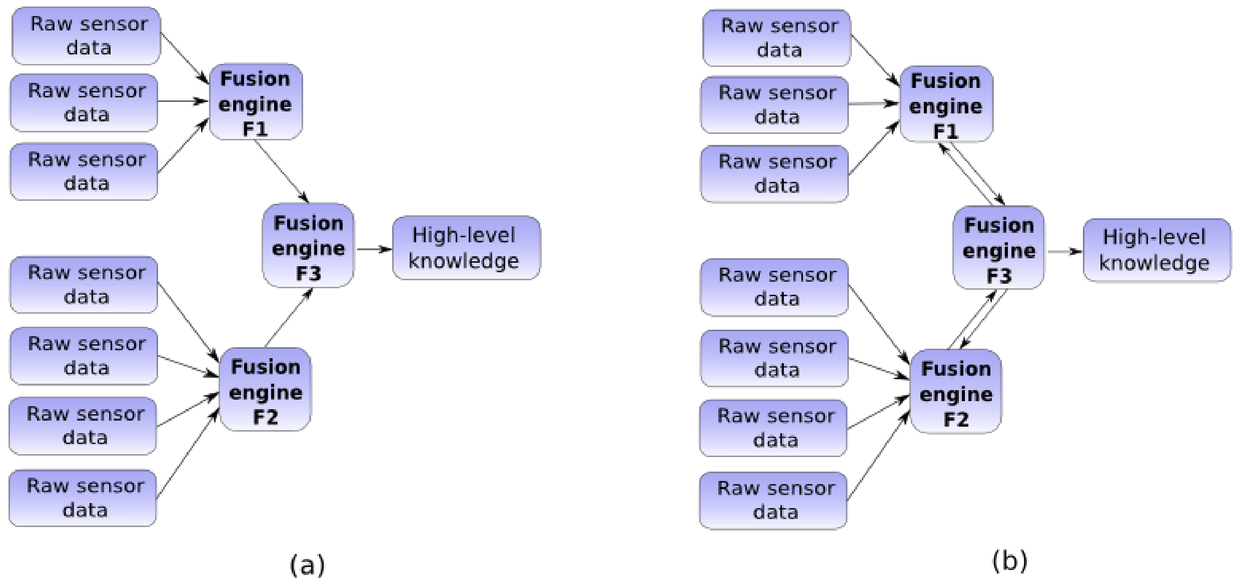

Fig. 4-10. Hierarchical Data-Fusion Architectures

There are several advantages to hierarchical data-fusion schemes (Varshney, 1997). It requires significantly less communication bandwidth because a low-level fusion node receives data from a smaller number of sensor nodes compared to the case of centralized fusion. Plus, the data volume transferred between any two fusion nodes is significantly smaller than the raw sensor data size because the fusion nodes usually transfer aggregated information at a higher level of information abstraction with a more compact representation than raw sensor output. In addition, each fusion node requires smaller computational capacity because the computational tasks are distributed across multiple fusion nodes. These also do not have any single point of catastrophic failure and, hence, are more resilient.

The extreme case of a distributed and decentralized data fusion framework is one in which there are no designated fusion engines but a network of sensors, as a whole, produces the desired fused output through cooperative computation. Such computational frameworks are known as “swarm” algorithms (Yiyue et al., 2012). Such systems are more robust and fault tolerant than centralized or semi-centralized architectures because the swarms are robust against the failure of a subset of nodes. There is no predefined communication hierarchy or topology and the network is capable of autonomously reconfiguring its communication pathways if a set of nodes happen to fail. Also, adding new nodes into the system is seamless. This makes this type of architecture highly scalable.

Despite these advantages, the distributed and decentralized fusion architectures pose a number of challenges. In the hierarchical scheme, it is not trivial to design an optimal architecture, such as defining the assignment of sensor subsets to first-level fusion nodes and the communication topology for the fusion nodes. Also, one cannot take a centralized fusion algorithm and apply it in a hierarchical fusion system. The algorithms need to be tailored to the architecture, which is not an easy task. Designing a swarm-based algorithm for data fusion is likely the most complex of all the decentralized fusion schemes. This has led to research to address these challenges (Moses et al., 2006; Chair and Varshney, 1986; Durrant-Whyte et al., 1990; Julier and Uhlmann, 2001; Makarenko and Durrant-Whyte, 2004; Rao et al., 1993).

4.6.9 Data Fusion Process Model

Data fusion systems are highly domain specific, and there is no one-size-fits-all solution that can be deployed without considering the specific requirements for the application. Because of such diverse system requirements, it was important to develop a common descriptive substrate to elucidate the core concepts of data fusion as a discipline. This led to the development of the data-fusion process model which decomposes any data fusion task into a set of six subtasks, or levels. This general process mode is applicable across diverse application domains (Steinberg et al., 1999; White, 1988).

<u>Six sub-tasks for data-fusion processing</u>

Level 0: Source Preprocessing/Data Alignment

Level 1: Object Refinement

Level 2: Situation Refinement

Level 3: Impact Assessment (or Threat Refinement)

Level 4: Process Refinement

Level 5: User Refinement (or Cognitive Refinement)

Source pre-processing is one of the most fundamental steps in any data-fusion framework. Here, the raw data are subjected to a set of conditioning steps to make them ready for fusion. Examples of such conditioning are noise reduction for noisy images, color space translation (such as conversion of color images to monochrome images), orienting all geo-spatial data to north up, scaling all data to a desired range, etc. It is important to understand that no actual fusion of data from different sources takes place at this level. One particular pre-processing—*data alignment* —task deserves elaboration as it is almost ubiquitous in data fusion applications. Data alignment refers to the task of bringing raw data from all the sensors to a common representational framework so that one can make a valid comparison and assess the similarities or dissimilarities among the data. Data alignment is not a simple or easy task by any means. In fact, this can be one of the most critical steps in a data fusion pipeline. If the alignment is incorrect; all subsequent analyses will produce incorrect inferences.

The situation gets far more complex when the sensors are heterogeneous in nature. For example, if one installs microphones to detect human voices in areas where cameras may not be deployed or carbon dioxide sensors to get an estimate of the number of people, the data from all these different sensors need to be aligned before they can be fused to make a unified interpretation. Aligning such disparate data sources is a challenging task.

Level 1: Object Refinement

The core task is to fuse the Level 0 data from the various data sources to identify items of interest. Sensors can have different resolutions, angles of view, or other characteristics. The classification step essentially groups the identified items into categories. The processes used in Level 1 are highly application specific.

Level 1 processing becomes especially challenging when a larger number of items are to be tracked. Not only does the computation complexity increase, but the situation injects uncertainty and ambiguity through occlusions, overlaps, and track intersections (Uhlmann, 1992; Bar-Shalom and Li, 1995).

Level 2: Situation Refinement

The goal of Level 2 is to determine relationships among the detected targets/entities as well as the environment to extract a context. The targets (objects, spatio-temporal events, etc.) detected in Level 1 need to be aggregated in this stage to obtain desired contextual knowledge. Besides aggregating target objects, it is also useful to aggregate the temporal information of events because the same event can imply a vastly different context depending on its time of occurrence. A time sequence also can provide insight. A sequence of events in a specific time order can provide valuable contextual information about a situation.

Level 3: Impact Assessment

The essence of impact assessment is to extrapolate the situational awareness obtained in Level 2 to forecast the evolution of the scenario in the future. This requires prediction based on currently observed events and estimating the ramifications of those events.

Level 4: Process Refinement

In essence, process refinement is not part of any core fusion task, but it refers to the auxiliary task of monitoring the performance of the current fusion infrastructure and dynamically modifying aspects of the framework to achieve optimal performance. For example, the sensors may need to be re-oriented to improve coverage, or the Level 1 fusion may need to be switched from a lower level fusion mode to a higher decision level fusion.

Level 5: User Refinement

Level 5 involves the process of incorporating a human-in-the-loop facility by incorporating various human-computer interaction (HCI) mechanisms into the data-fusion pipeline. Examples of such HCI methods are information visualization, haptic feedback[17], and verbal interaction (Preece et al., 1994).

4.6.10 Characteristic Interdependencies

Any data-fusion task involves a set of subtasks. The fusion model formalizes these subtasks into six levels as elaborated in section 4.6.9. However, each of these levels can be decomposed further depending on the application domain. Most of these subtasks represent interdependent problems.

The most basic interdependency is between Level 0 pre-processing and estimation of the various states of the target. The uncertainty in these state estimates is highly dependent on the fidelity of the data-alignment task. Any error in data alignment will likely be amplified in the subsequent stages of the fusion pipeline.

Another crucial interdependency is between the uncertainty in the final fused result and the uncertainty in the data gathered by the sensors. Uncertainty in raw sensor data can arise from various sources, such as sensor calibration drift, uncertainty in the location of the sensor itself (e.g., in a GPS-denied environment), uncertainty in the location of a target (e.g., when the target is occluded), etc. Such uncertainties, if not taken into account in the fusion process, can have significant impact on the accuracy of the fused output.

The communication bandwidth among the sensors or between a sensor and a fusion engine can affect the choice of fusion architecture to use.

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[17] Tactile feedback such as vibrations

The available power source also determines the type of fusion system to be deployed. For example, in a building surveillance system, all sensors, as well as the fusion engine, can draw power from the buildings electrical infrastructure. So, power availability is not a constraint. Hence, they can operate almost indefinitely and be of a permanent nature. However, if we want to deploy a set of temporary sensors, or sensors without a hard-wired power source, this will impose limits on the architecture. For example lightning detection solutions and in particular, the CS110 EFM is in my case a solar powered solution.

Criticality of the fused product influences the architecture of the data-fusion system as well. If it is imperative, for some reason, to collect data without interruption, it is essential to build as much redundancy into the system as possible within the constraints of the project. Lack of redundancy in this case, can result in loss of data.

4.6.11 Typical Applications

Data fusion has tremendous potential in the building management domain by reducing the cost of day-to-day operations and maintenance through efficient coordination of various active components such as HVAC, electrical systems, and mechanical systems, as well as reducing waste of valuable resources such as water and power. Operation and maintenance are usually the most expensive elements of a building's life cycle expenses, and these costs usually increase over time as a building gets older. An appropriate sensor fusion framework installed in a building can significantly reduce these costs. Bogen (Bogen et al., 2011) states that, "… *approximately $15.8 billion of annual U.S. capital facility industry efficiency losses* *are due to inadequate interoperability in design, engineering, facilities management*….” A sensor suite that is properly chosen and deployed in a building and the appropriate fusion of the data from these sensors can provide reliable, accurate, and actionable near real-time information that a building operations manager can leverage to make decisions about the most efficient control of the various components. This can result in substantial energy savings and reduced operational cost.

A key component in efficient building operations is real-time information about occupancy load distribution across a facility. If the dynamic occupancy profile can be determined in real-time, the information can be exploited for automatic dynamic control of lightning, temperature, air-flow, and other indoor environmental parameters to provide optimal comfort for the occupants without wasting energy on maintaining the same level of comfort in unoccupied areas. To determine a building-wide occupancy profile, it is necessary to deploy a suite of sensors of different modalities (such as temperature sensors, humidity sensors, visible cameras, infrared sensors, etc.) distributed throughout the building. Information from these sensors could then be fused to produce a unified and actionable knowledge product that can be used to optimally control the various building systems.

Another area of interest in energy efficient building management is predictive occupancy modeling. By discretely sampling the occupancy load distribution data obtained through multi-sensor fusion and archiving the data in a database over a significant period of time, machine-learning techniques can be applied to discern occupancy patterns. These patterns can then be used to predict spatio-temporal[18] occupancy and activate the systems appropriately to bring the relevant areas to the desired environmental state at the right time.

Human activity detection in an indoor environment has been an active area of research, motivated not only by energy conservation, but also by other application domains, such as gaming. However, the fundamental technological advances resulting from these diverse research activities can be exploited in smart building management systems. Coen (Coen, 1998) carried out one of the earliest instances of research about tracking people and activity detection in a room. His team used multiple sensors to detect locations of people and their activities and offered automated help using artificial intelligence algorithms. Mozer (Mozer, 1999) developed a framework where a building learns by observing occupant behaviors over time. The key differentiator of this research was that the building had the ability to adapt its functionality to the inhabitants' desires and habits.

At a finer level, data fusion can play an important role in getting reliable estimates about the state of a specific sub-system in a building. For example, Huang (Huang et al., 2009) developed a data fusion scheme for improving the measurement of the cooling load in chiller plants in buildings.

4.7 Summary

This chapter began by reiterating our research questions originally proposed in Chapter 2 along with thought questions to keep in mind during the evaluation of

[18] Belonging to both space and time

our methodology for answering our research questions. The chapter then covered the highly relevant topic of sensor data fusion. Understanding this process is important to our research questions and broader implications of the solutions to be presented in Chapter 5 along with broader implications of this research to be presented in Chapter 6.

Chapter 5: Conclusions, Findings and Implications

This chapter presents the research findings placing them within the context of the environmental and cost implications discussed in the previous chapters. The chapter is organized in the following manner: Section 5.1 presents the rational for choosing the incumbent category of sensors and discuss the Hatchett case study. This will be followed by section 5.2 where I will outline the specific sensors chosen, the measurement system design, how the sensors and system operates as well as the data measured. Sensor installation – included installation verification procedures – is presented in Section 5.3. The process used for the instrumentation field measurements is in Section 5.4 while Section 5.5 discusses the measurements and their implications. Section 5.6 will take a practical approach by calculating the potential risk reduction of such a system ($USD). Section 5.6 also presents the cost and benefits of the deployed lightning and charge sensor system. In the face of the lightning threat[19], formulas and calculations will be presented that will assist planners, operators, and managers of large hydrocarbon storage facilities[20] with the mitigation of the lightning threat.

Section 5.7 will examine the usefulness of this system design to industry in general. The chapter concludes with section 5.8 in which I will summarize final thoughts and implications from this chapter concluding with final thoughts on risk if no further action is taken by industry.

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[19] A 2014 research paper published in Science by Romps et al., University of California Berkley supports a 50% increase in in cloud-ground Lightning strikes during this century due to the realities of global warming

[20] A detailed multi-decade study of 242 hydrocarbon storage tank accidents by Chang et al. showed that 33% were cause by lightning.

5.1 Category of Sensors selected and Test Site

As discussed in prior chapters, there are a wide array of sensors and systems that were candidates for use in the experimental phase of this dissertation. The categories of sensors used in this research are presented in this section.

5.1.1 Rational for sensor category selection

In order to answer the research questions posed in Chapter 2, the ability to measure an approaching lightning threat in real-time is required. As was explained in Chapter 4, other prominent methodologies used to measure lightning frequency and geolocation do exist.

One category is used by the National Oceanigraphic and Atmospheric Agency (NOAA) , their National Lightning Detection Network (NLDN). NLDN incorporates an array of geographically dispersed photonic (flash) detectors operating in a cooperative manner to geolocate and deconflict lightning flashes (details in Chapter 4). Unfortunately for my research I was not able to access NLDN data, for they will only provide raw data streams to the Government and Military. The public has access to processed subset data that is (at best) months old.

The second category of lightning detection sensors leverages the radio emissions (3-30 KHz) from the energetic discharge associated with a lightning event. As described in Chapter 4, a cooperative organization based in Germany has a basic solution that starts at 200 Euros. This small entry price will allow you to be a good citizen of the world by contributing an RF (radio frequency) emission and GPS (with time stamp) measurement node. This TOA (Time of Arrival) and TGOA (Time Group of Arrival) information is fused in a central repository with other nodes. While this is a promising solution, it is not real-time and you don’t own the data. Furthermore, commercial use of this data is forbidden.

With the incumbent solution, the user owns the data. Plus, cooperation with multiple devices is not required, but could be beneficial (see chapter 4; data fusion) If data fusion is leveraged, the atmospheric charge sensors and the tank charge sensors present a unique opportunity to assess the approach of a lightning and charge threat. The corollary is also realized though a drop in energy of the atmospheric charge sensor and tank charge sensor.

5.1.2 Hatchett case study

The primary reason for choosing the Hatchett lease battery - located near Midland Texas - for this research was the easy access and availability of the battery tanks that were required upon which measurements could be used to determine the validity of answers to the research questions posed in Chapter 2. A representative google earth image of the Hatchett Battery is presented as Figure 5-1. The tanks in use at the site were a mixture of fiberglass and welded steel.

Fig. 5-1. Hatchett deployment site with weather station visible

Specifically, some tanks were all metal, and some were all fiberglass whereas one we even constructed with a fiberglass “cap” atop a steel body. The tanks were on the order of 500 bbl[21] each in volume and were 16’ in height with about a 15’6’’ foot diameter. For the sake of a common reference, a tank would hold 21,000 U.S. Gallons of crude oil if full. The fiberglass version of this tank costs about $16,700[22] without shipping or instillation costs. At today’s WTI crude price of around $50 / bbl, each tank can hold $25,000 worth of crude oil. However, tank sizes range greatly from 27 bbl to 1000 bbl for local battery sites. --- Regional crude storage sites have tanks holding many thousands of bbl. ready for transport by rail (Fig. 5-2).

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[21] 1 bbl (barrel) of crude oil in the U.S. = 42 gallons
[22] http://www.jmackenergy.com/GUNBARREL-TANKS/

Fig. 5-2. Regional crude storage for rail transportation – Rooke 2014

5.2 Chosen sensors, their data and functionality

I collaborated with ORNL for the selection and procurement of system components that met specifications for the required tests. My involvement centered around selection of components and the verification and calibration of the system following deployment. While my research questions are key to my dissertation, answers are also of use to PXD and other fracking production companies.

5.2.1 Atmospheric charge sensors

Using uniquely integrated Common Off The Shelf (COTS) components, a multi-parameter sensor station was developed and deployed at the Hatchett site to facilitate local atmospheric measurements. Some key goals and considerations are outlined here:

- Measure local weather conditions.
- Measure electric field in the local atmosphere.
- Measure local lightning strike activity.

- No local power or communications available.

Local weather conditions such as humidity, wind speed, and direction can be accurately measured with this this sensor station. More importantly, the atmospheric electric field can be accurately measured; results to be presented in section 5.5. In addition, this customized device has a lightning detector with event range monitoring. While the Hatchett site does have electrical power, it was not available for this experiment. So, a 20 watt solar panel with a rechargeable battery was used to power this instrument cluster. The desire was to have a standalone system that did not depend on the site for electrical power. Part of the reasoning behind this is the lack of power access in the Midland “boomtown” environment. The local utility will often charge around 1 Million dollars for a modest power line with grid access. Thus, having an independent instrument cluster is an important feature. Communications were accomplished every 10 minutes through a satellite directed antenna called out as the “Cell modem antenna” in Fig. 5-6.

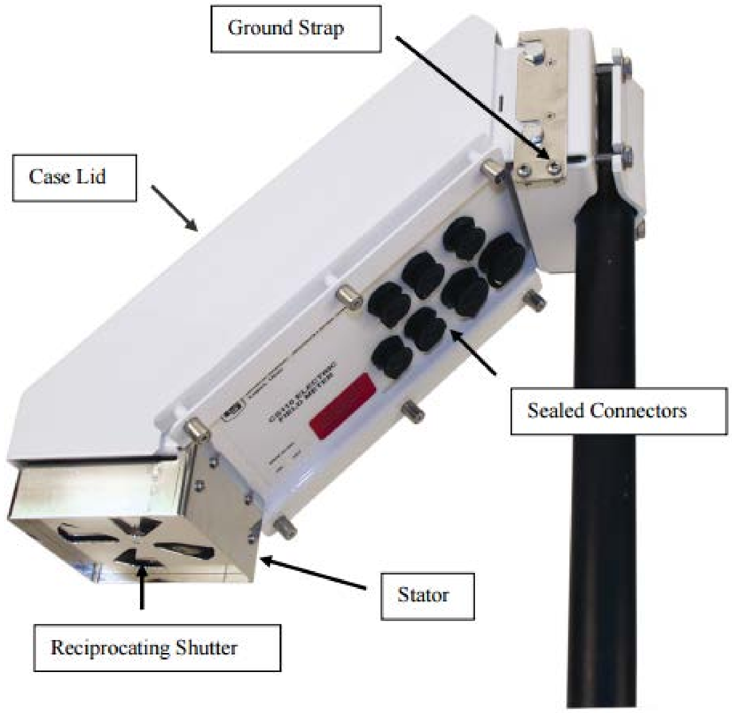

Fig. 5-2. Campbell Scientific CS110 Electric Field Meter[23]

Each CS110 is calibrated in the factory in a calibration chamber as shown in Fig 5-3. The reciprocating shutter opens and closes during measurements. It is electrically connected to the ground potential and upon the shutter opening the electric field of the atmosphere is taken. The difference between the two measurements provides a user with the voltage potential difference. Thus, the degree to which the atmosphere is “energized” and capable of producing lightning can be considered for activation of the IPL (Independent Protection Layer) for lightning mitigation.

[23] http://s.campbellsci.com/documents/us/manuals/cs110.pdf

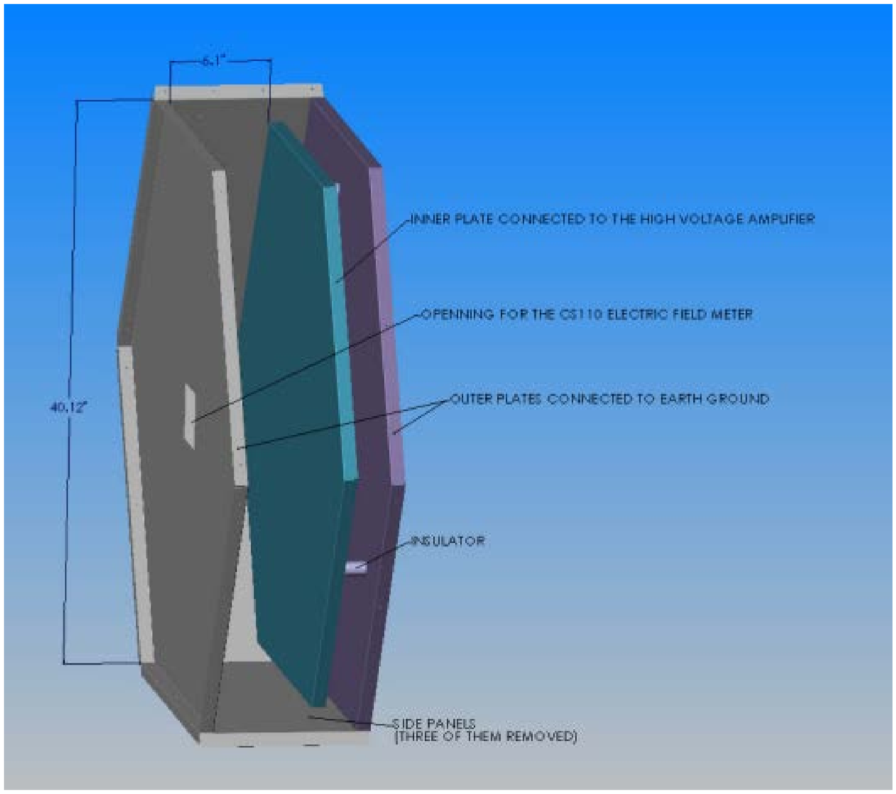

Fig. 5-3. CS110 Calibration Chamber

During calibration, Eq. 5-1 is used where data is plotted with the goal to obtain a R^2 close as close to 1.00 as possible (strait line); in fact, the instrument is calibrated to this standard. The term $M_{parallel\_plate}$ is related to the size of the electrode in the CS110 and feedback from the capacitor in the charge amplifier. Whereas the term $O_{parallel\_plate}$ is in essence the measure of how “dirty” your electrode is and represents unwanted surface charges from non-conductive deposits on the electrodes.

$$\mathbf{E = M_{parallel\_plate} \cdot V + O_{parallel\_plate}}$$

Eq. 5-1

Once in the field, the instrument must be calibrated to meet site specifications. The factory calibration is only valid for an instrument mounted flush with the earth; this is not realistic for a field instillation due to weather (water intrusion) and general debris associated with a long-term field deployment (see section 5.3).

5.2.2 Tank Sensors

The operational criteria for the tank sensors was a combination of proper dynamic range and the availability of COTS components. After literature and industry surveys, few commercial sensing options were identified. The search ended with the textile industry and Monroe Electronics. Components were ordered from Monroe and an electrostatic fieldmeter sensor was adapted for tank usage whereas before, the components were designed to monitor static charge on textile web materials. The installed static sensor system for tanks have the following design characteristics:

- Sensors must measure electric charge at tank surface locations.
    - o +/-40KV charge measurement range
    - o Input resistance of > 10^12 ohms
- Tank locations are Class 1 and Division 1 rated[24].
- No local power or communications available.
- Flexible and easy to install.

To accomplish these operational goals, I consulted with ORNL who then worked with Monroe to develop a “charge plate” concept. This was principally done to protect the sensor and from weather by bringing the tank surface charge to the sensor via the charge plate.

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[24] Class I, Div. 1 – Locations where ignitable concentrations of flammable gases, vapors or liquids are atmospherically present on a continuous basis or often under normal use conditions. – NFPA 70 (National Fire Protection Association)

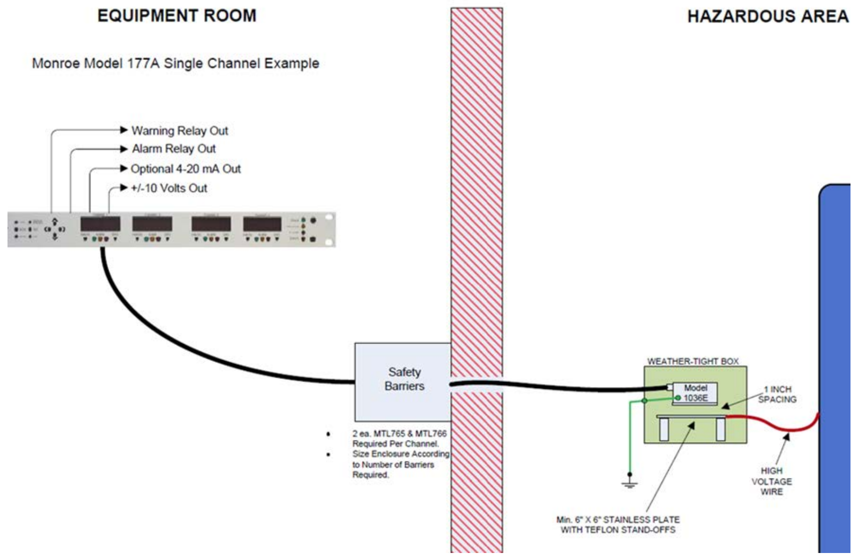

Fig. 5-4. Overview of deployed tank charge sensor

As an added benefit, the Monroe 177A electrostatic fieldmeter could reliably monitor static buildup in the weather tight instrument hut. For a closer look at the electrostatic sensor and its isolation box, see Fig. 5-5.

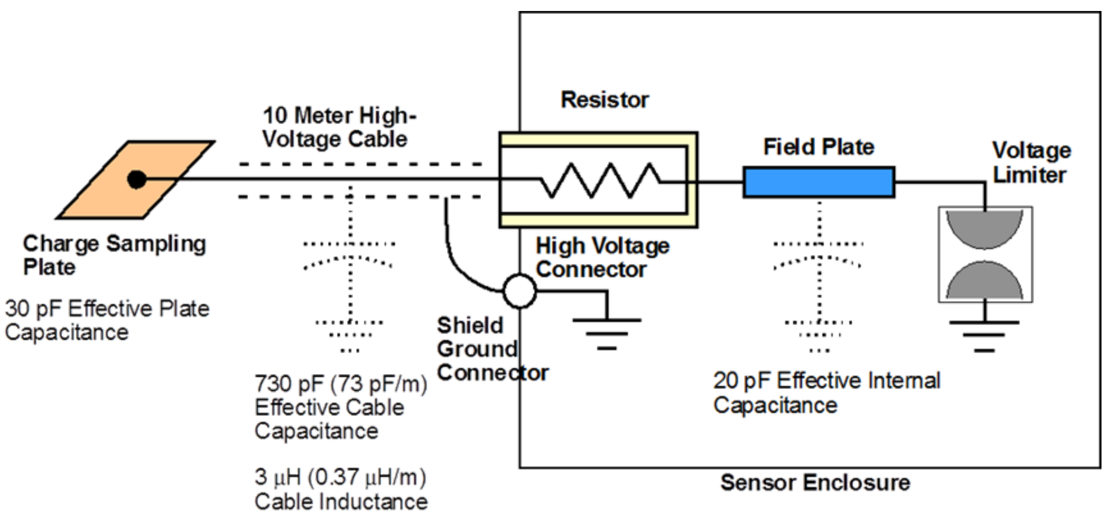

Fig. 5-5. Electrostatic sensor and isolation enclosure

Since it is well documented by Chang (Chang and Lin, 2006) and others that electrical storms induce a charge on fiberglass storage tanks from a distance of 15 –

150 km sometimes resulting in documented cases of arcs and subsequent fires. Thus, tank charging during storms is important to this research. Instillation location is a key variable that will be discussed in section 5.3.

5.3 Installation and verification of sensors

5.3.1 Atmospheric sensors

I was mindful of component interoperability and the need to meet system requirements for this sensor deployment. This was described in section 5.2.1, the CS110 chosen as the Electric Field Monitor due to its well documented performance[25]

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[25] http://s.campbellsci.com/documents/us/manuals/cs110.pdf

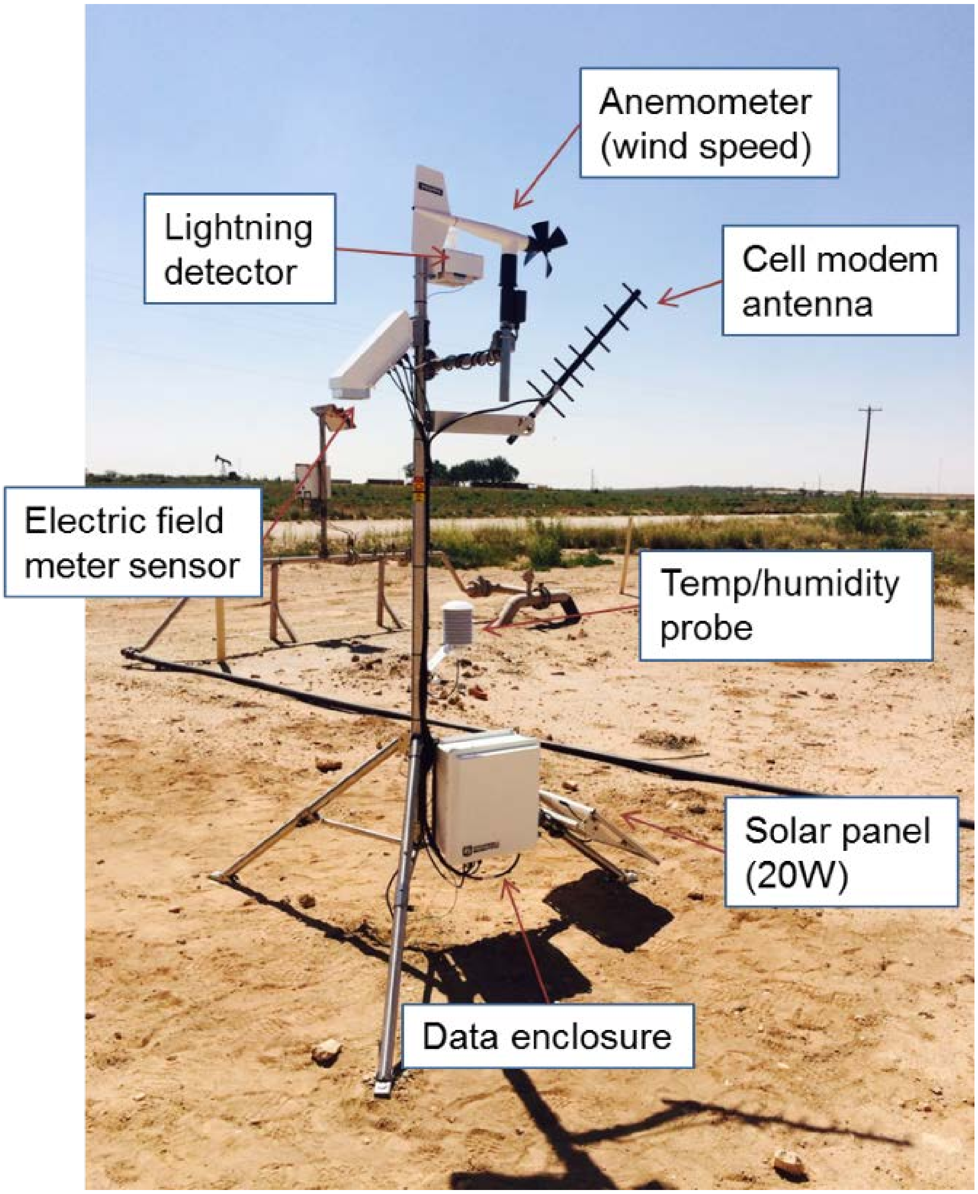

Fig. 5-6. Deployed weather station with CS110 electric field meter sensor

Installation of the "weather station" with an atmospheric charge (CS110) sensor was a mostly a drop in place process, with some acceptations. The CS110 is a Common Off The Shelf (COTS) product built by Campbell Scientific and marketed as an Electric Field Meter[26].

The CS110 was mounted in a slightly inverted manner has shown in Fig. 5-6. By doing this, the effective gain will be reduced; however, unwanted electric fields will also be reduced thereby enhancing the desired gain. By using Eq. 5-2 at the Hatchett site, I verified the R^2 to be .997.

$$\mathbf{M_{corrected} = C_{site} \cdot M_{parallel\_plate}}$$

Eq. 5-2. CS110 Field calibration

For the terms in Eq. 5-2, $M_{corrected}$ is the correct multiplier whereas $M_{parallel\_plate}$ is unique to every CS110 and independent of the site deployment. C_{site} is the site specific term and can be impacted by vegetation and other nearby objects. In addition, the filed calibration should be done in the absence of precipitation or foul weather. An example of an in-field calibration is shown in Fig. 5-7. It is common factor in -100 V/m as a fair weather correction factor[27].

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[26] http://s.campbellsci.com/documents/us/manuals/cs110.pdf

[27] A negative sign is used to indicate the electrostatic force on a positive charge exhibited by the earth.

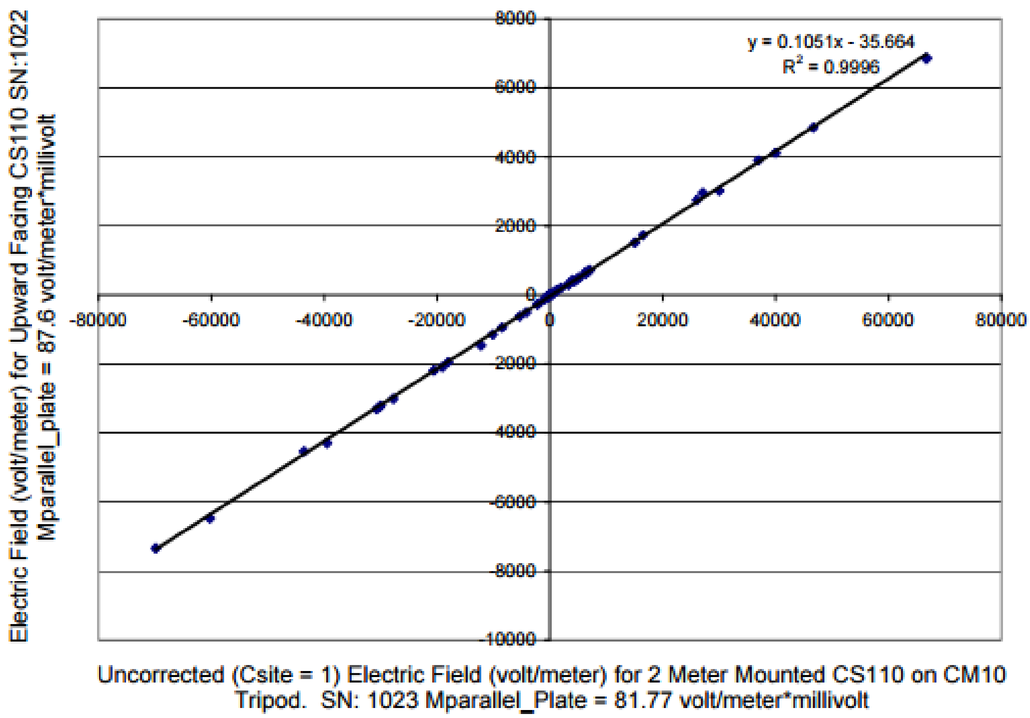

Fig. 5-7. CS110 Field Calibration plot

This infield calibration was part of the verification process. I became keenly aware of the need to keep electrode clean during calibration and the sensitivities the instrument displayed during high humidity mornings vs. dry afternoons; the instrument was calibrated during a dry afternoon on October 9th 2014.

Fig. 5-8. Alignment of satellite communication antenna – Rooke 2014

Since the Hatchett site is off a dirt road, about 45 miles from the Midland International Airport; communication and electrical power were a concern. Providing power to the weather station simply involved the deployment of a 20W solar panel and a rechargeable battery. Due to the strong West Texas sun, this setup was verified to supply sufficient power to the weather station.

As shown in Fig. 5-8, the station used a satellite modem for telemetry and transmitted measurement every 10 min. Alignment of the antenna was critical and was readjusted by me during the verification process.

5.3.2 Tank charge sensors

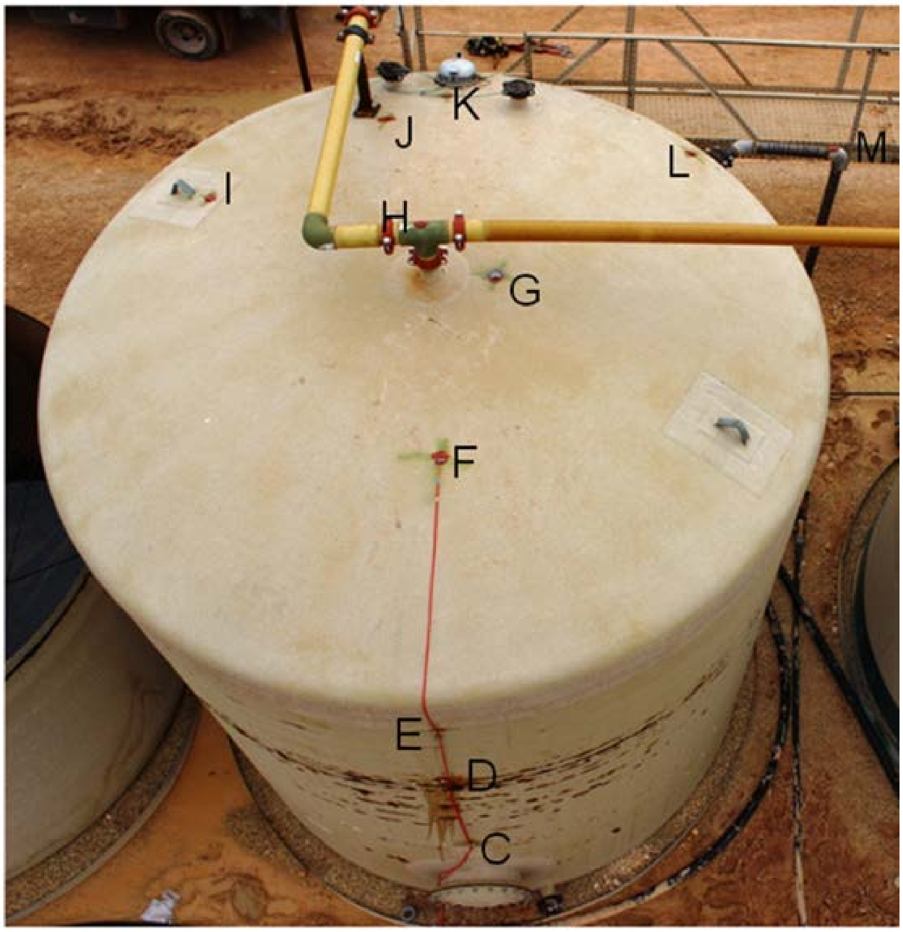

Fig. 5-9 Fiberglas tank charge sensor instillation at Hatchett

Fiberglass tanks were of particular interest since charge measurement of these types of tanks was supportive to answering our research questions. As Chang et al. and other have pointed out, electrical storms are capable of inductively charging tanks from a distance of 15 – 150 km (this will be further analyzed in subsequent sections of this chapter). Although the process for grounding a tank to dissipate charge buildup sounds simple, as others have experienced this is not an absolute solution (see literature research in Chapter 3). The instillation process involved choosing charge “pick-up” locations across various locations on the tank. There was no previous published basis for mounting charge pickup locations of these types of battery tanks with these specific connections and associated piping.

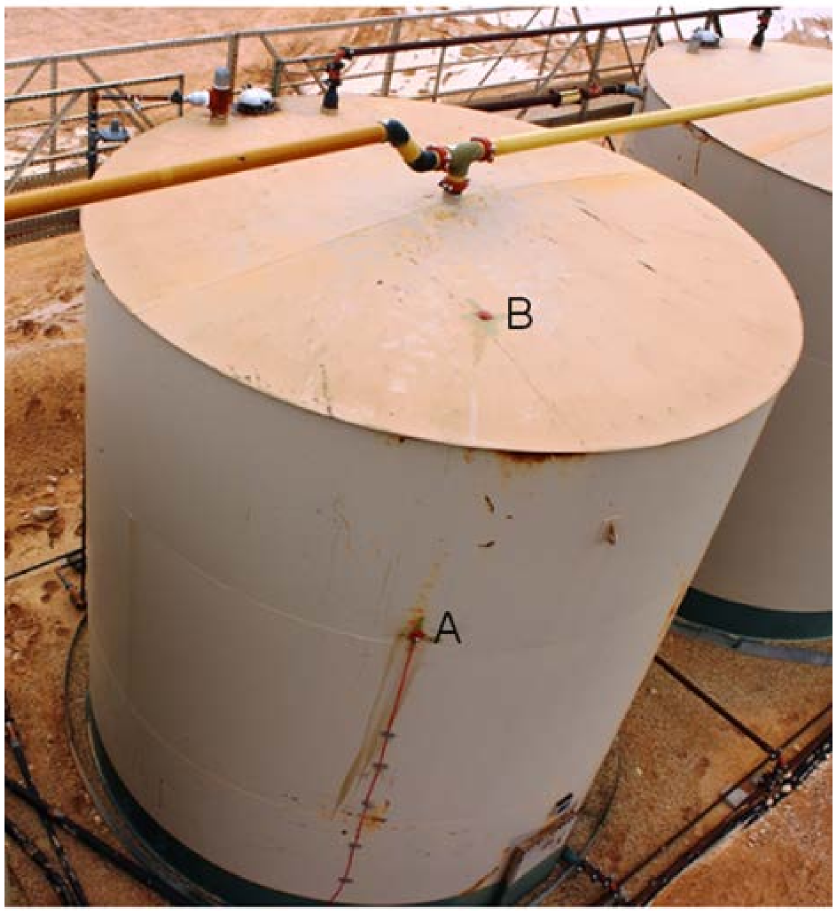

Fig. 5-10. Steel tank charge sensor instillation at Hatchett

In a similar manner to the fiberglass tanks, the steel tank leveraged a similar instillation method. However, there were only 2 pickups as the steel tank was more of a control and not the direct object of study. Steel tanks dissipate charge buildup much more rapidly than fiberglass due to their inherent conductive properties.

Enclosure/ Channel	Tank Attachment
1	A
2	B
3	C
4	D
5	E
6	F
7	G
8	J

Table. 5-1 Wiring diagram of tank charge sensors

Table 5-1 shows the wiring diagram for the tank “pick-ups”. Charge information will travel along the accompanying wires to a charge transducer located in the instrument “hut” at Hatchett (Fig. 5-11). This building housed any weather sensitive instruments including the ones outlined in Fig. 5-13.

Fig. 5-11. Instrument “hut” at Hatchett

Fig. 5-12 details all the major components housed in the data hut. This provided a weather tight and environmentally stable enclosure for sensitive measurement equipment.

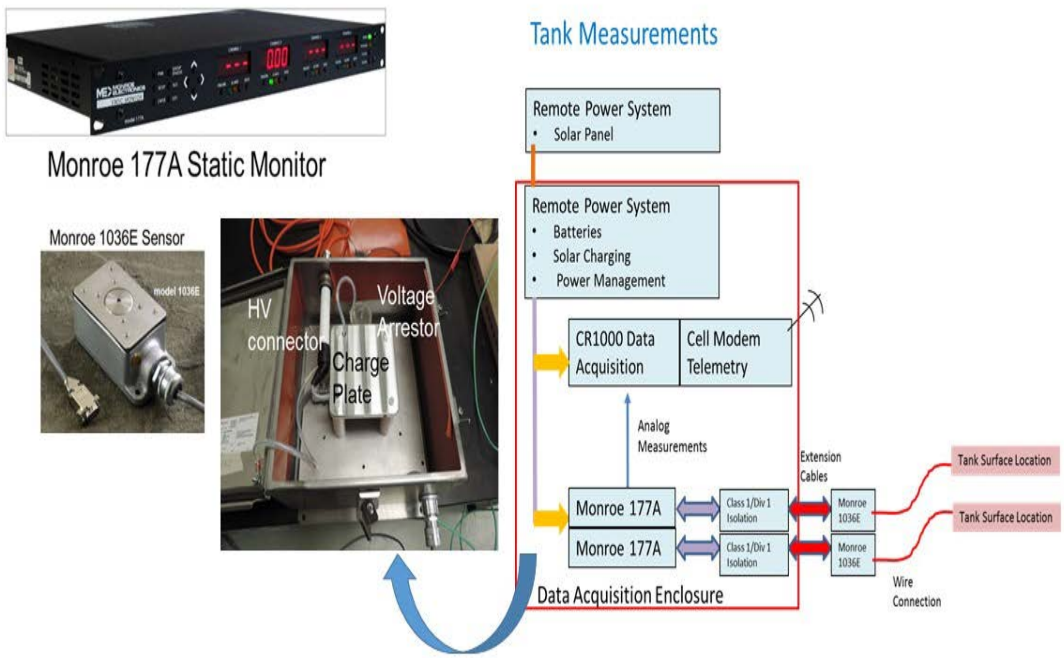

Fig. 5-12. Instruments for charge measurement of tanks

5.4 Instrumentation field measurement process

5.4.1 Atmospheric sensors

While the deployed solution is in a constant state of operation system errors due sometimes occur causing system crashes. Furthermore, due to the dusty weather conditions of the Midland area, the CS110 requires occasional cleaning. Its current form factor is not conducive for a long-term, zero maintenance solution.

5.4.2 Tanks charge sensors

The charge measurement process was highly dependent on a storm of adequate strength passing within the charge footprint (see Fig 5-34) Due to idiosyncrasies with equipment, including the Monroe 177A, system “crashes” were a reality. Thus, a technician was required to be local during testing, and hopefully a significant electrical storm would pass by during that time.

5.5 Measurements and Implications

The measurements obtained did indeed indicate an approaching lightning storm. Implications of these results support the efficacy of such a system for the prediction of a near-term lightning events. Further implications will be discussed in greater detail in sections 5.6 – 5.8 and by extension chapter 6 as a whole.

5.5.1 Atmospheric sensors

The atmospheric Electric Field Monitor (EFM) was a CS110 made by Campbell Scientific. Thus, as expected the CS110 performed to specifications described in the user’s manual[28] Results are shown in the following Figs. throughout this section.

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[28] http://s.campbellsci.com/documents/us/manuals/cs110.pdf

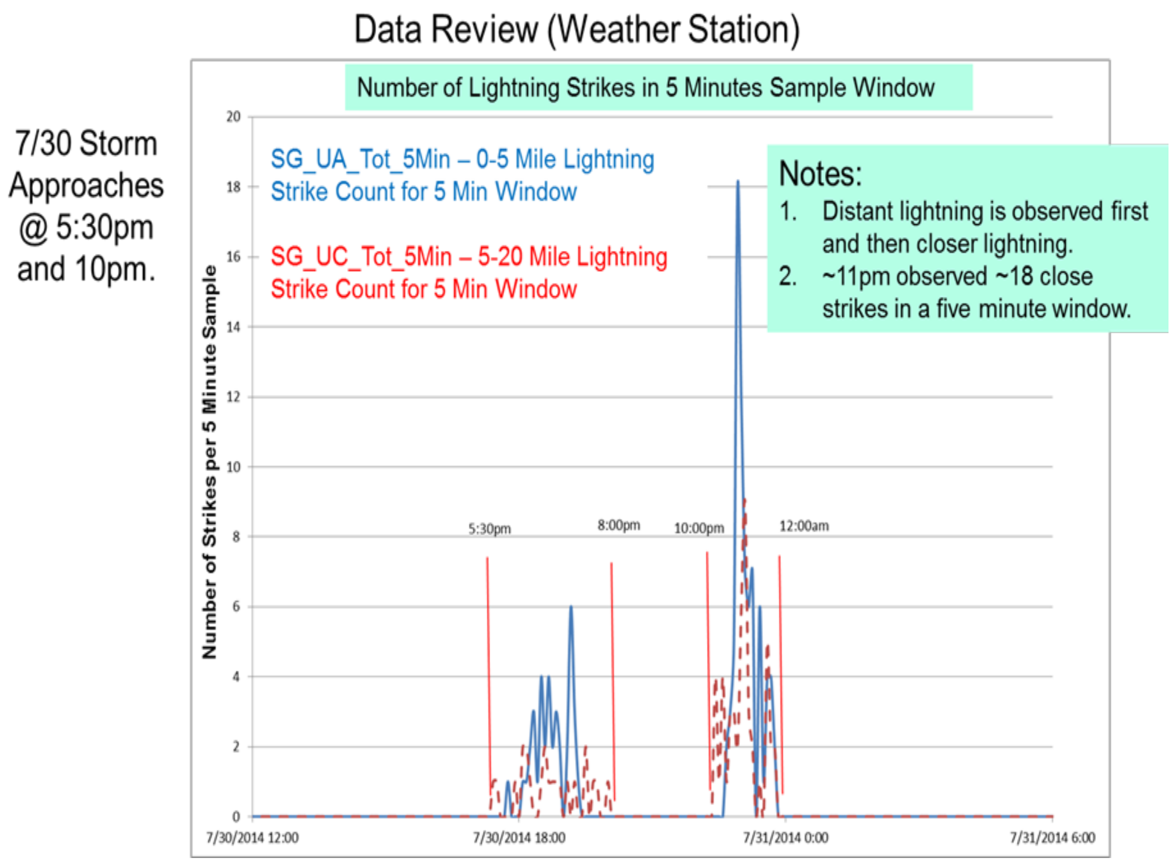

Fig. 5-13. Measured Lightning Strikes

Fig 5-13, helps to provide a backdrop for EFM readings with the CS110 to be shown in Fig. 5-14. So, when studying these results, take note of the time and date stamps as they correlate. By NAVSEA (U.S. Navy) 2000 V/m and NOAA standards of 1000 V/m correlating a lightning strike “warning”, Fig. 5-15 does indicate a 500 V/m EFM drop about 10 minutes before lightning first strikes. Thus, the predictive abilities of the CS110 have been replicated in this field study. Furthermore, many other high V/m swings measured with the CS110 correlate with actual lightning strikes in the area. If the area under the plot in Fig. 5-15 is integrated, it is representative of the intensity of the electrical storm. However, these details have not been fully quantified.

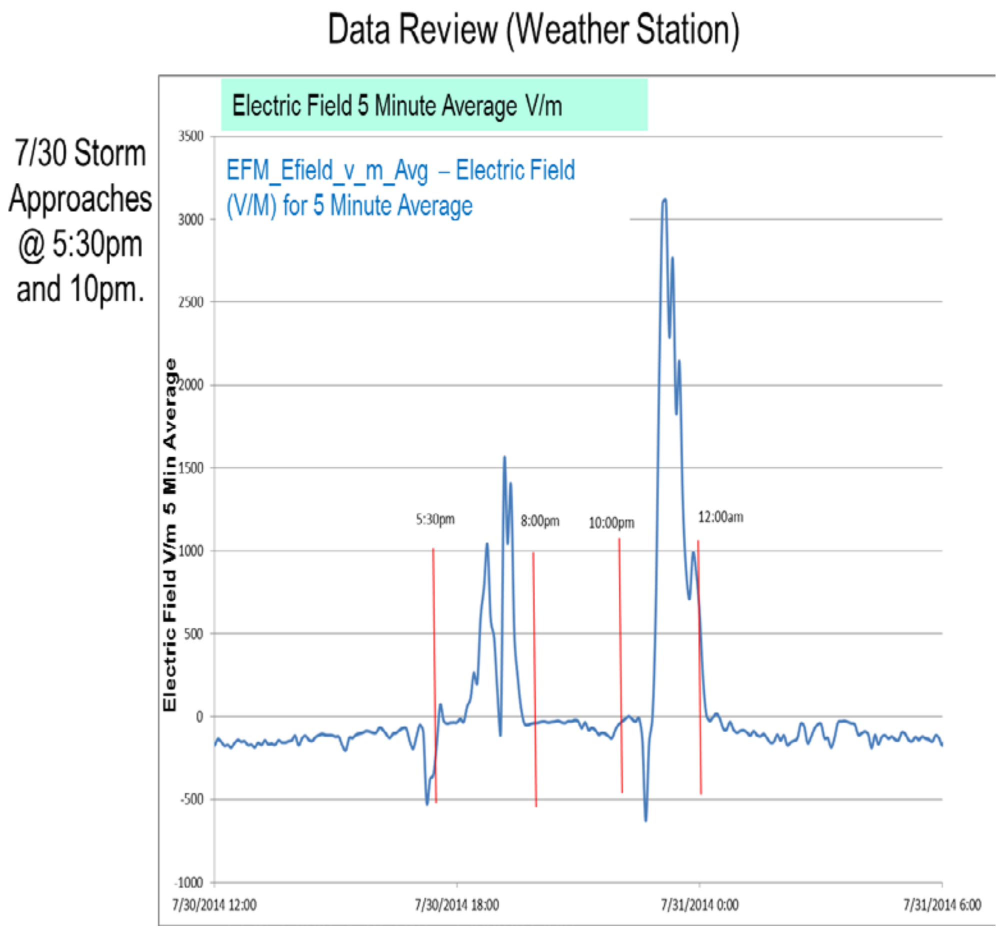

Fig. 5-14. Electromagnetic Field strength during storm event

Since the CS110 showed promise in a storm event at the end of July 2014, a long-term experiment was setup to gauge the stability of the CS110 and its precision and accuracy in predicting and measuring electrical storms. Fig. 5-17 shows a test that gathered data for over a month. The instrument was found to present characteristics of accuracy, but lacked precision in the quantification of lightning strikes. This result was expected since deconfliction of lightning strokes can be challenging with a field charge sensor. This is one major advantage that the NLDN (NOAA) has since it used photonics and cooperative ranging and geolocation in the assignment of a unique lightning stroke. --- A presentation of accuracy and precision is now timely ---

Accuracy and precision can be explained as follows. If a process or measurement yields the same result independent of hitting a “target” than one could say the grouping is tight, and thus the precision is high. Where accuracy is not concerned with a grouping, and more concerned with the average result being on target. This can be better understood through study of the following figure.

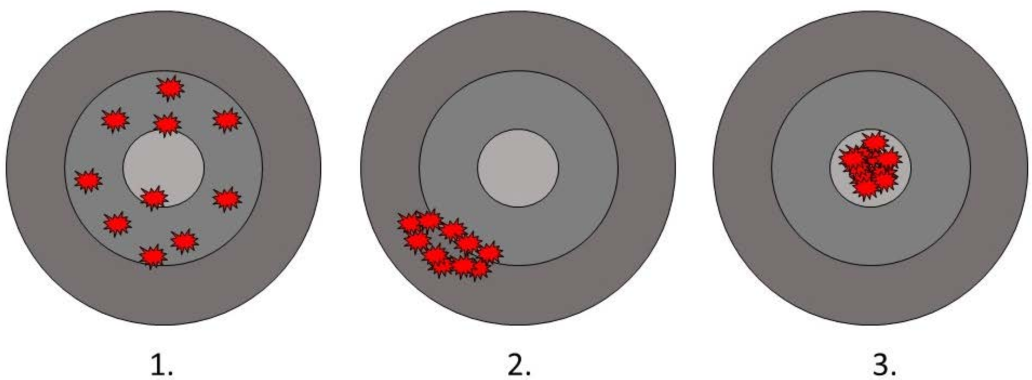

Fig. 5-16 Accuracy vs. Precision

In Fig. 5-16. , targets 1, 2, & 3 from a good introduction to the concepts of accuracy and precision. Target 1 shows a marksman that on average has great accuracy, yet lacks precision; this would be called a poor grouping. Target 2 shows great precision and somewhat poor accuracy; this marksman has a tight grouping yet is missing the mark; better check your gun sites. Besides gun sites, another way of saying the same thing could be your system or instrument is repeatable, but is consistently incorrect in the same way. Target 3 hits the spot; here we have both high precision and accuracy.

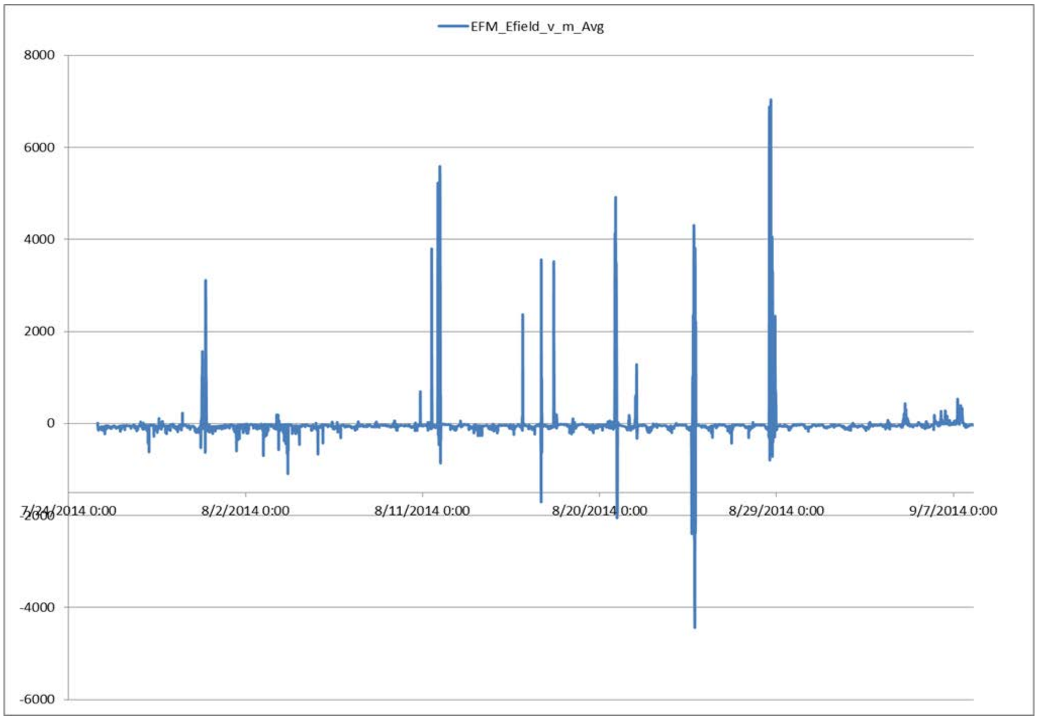

Fig. 5-17. Long-term field test of the CS110

The utility of the CS110 for the quantification of lightning stoke count is uncertain. From the preliminary results gathered from field tests, thus far the CS110 appears to be well suited for predicting possible lightening activity and ill-suited for deconflicting stroke count in highly active storms.

5.5.2 Tank charge sensors

Fig. 5-18. shows the mounting locations for the charge “pickups”. The lettered labels correspond to the data charts within this section.

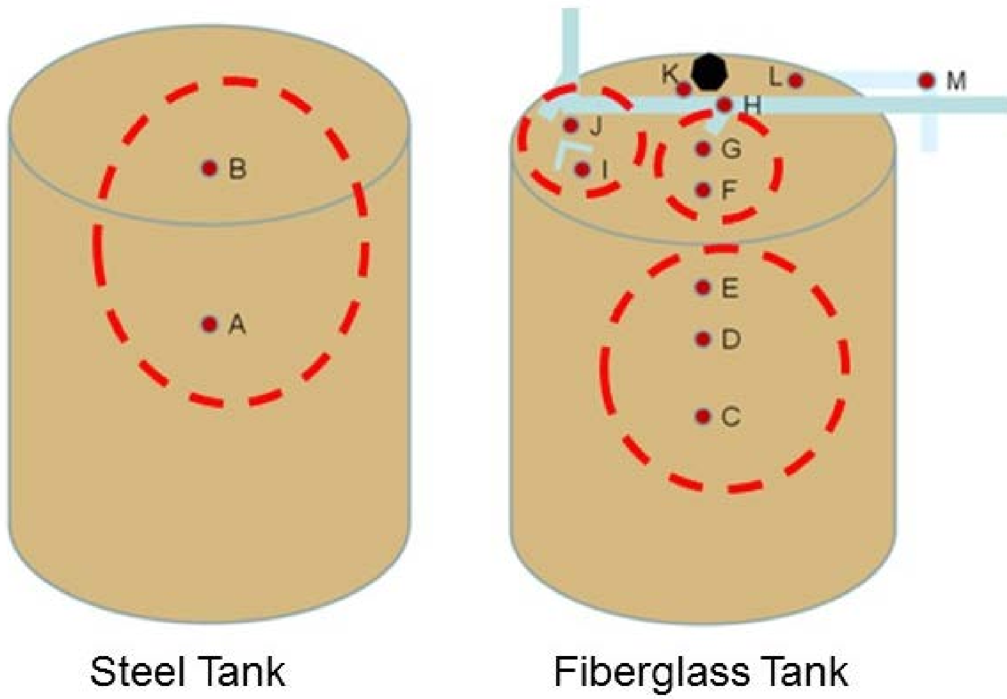

Fig. 5-18. Tank charge sensor “pickup” locations

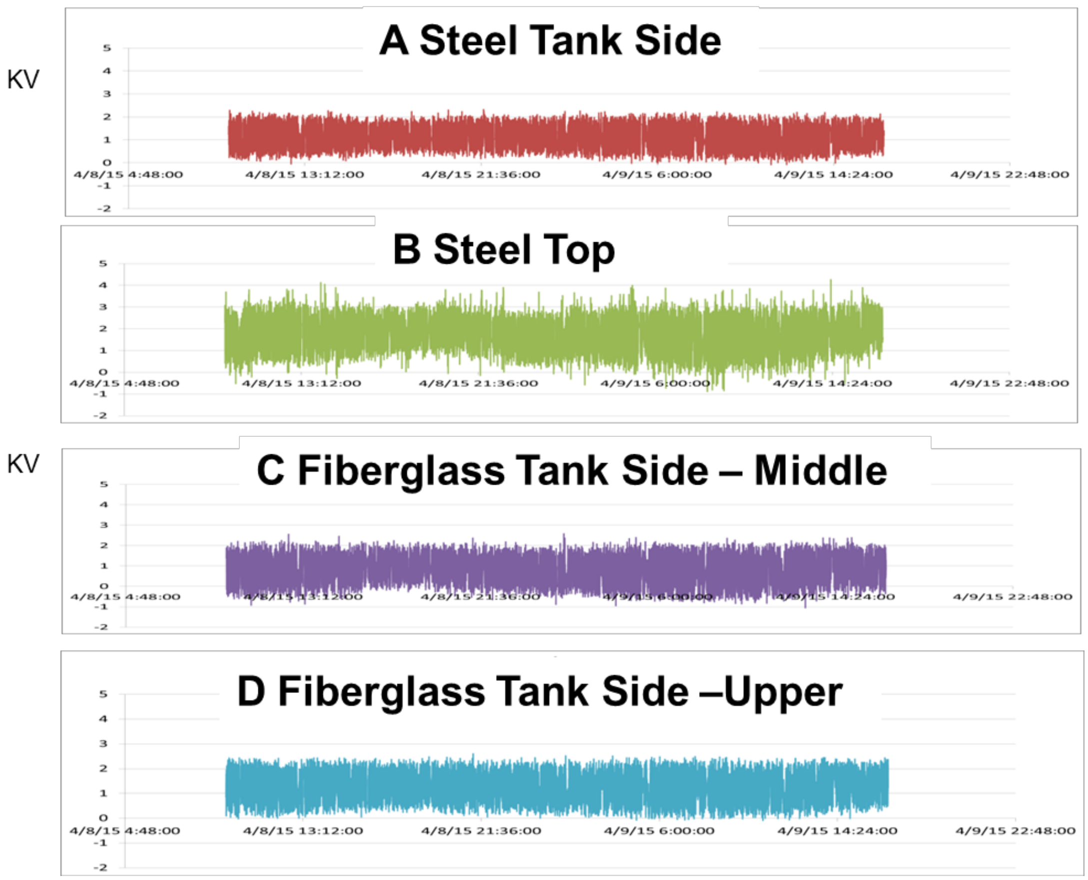

Fig. 5-19. Tank charge data; fair weather day (Part 1)

As expected, Fig. 5-19 shows data logged during fair weather conditions, none of the tanks showed a charge buildup. So, this data serves as a reasonable control for experimentation during stormy weather conditions.

Fig. 5-20 follows as expected and no "pickup" locations are showing unwarranted background charge. I now have a good baseline for experimentation during electrical storm events.

April 9th – April 13th 2015 were days of moderate storm activity around the Hatchett battery. As expected, Fig. 5-21 – 5-22 show some minimal levels of charging from some of the "pickup" locations. However, there was some level of disappointment since many locations did not show increased charge readings.

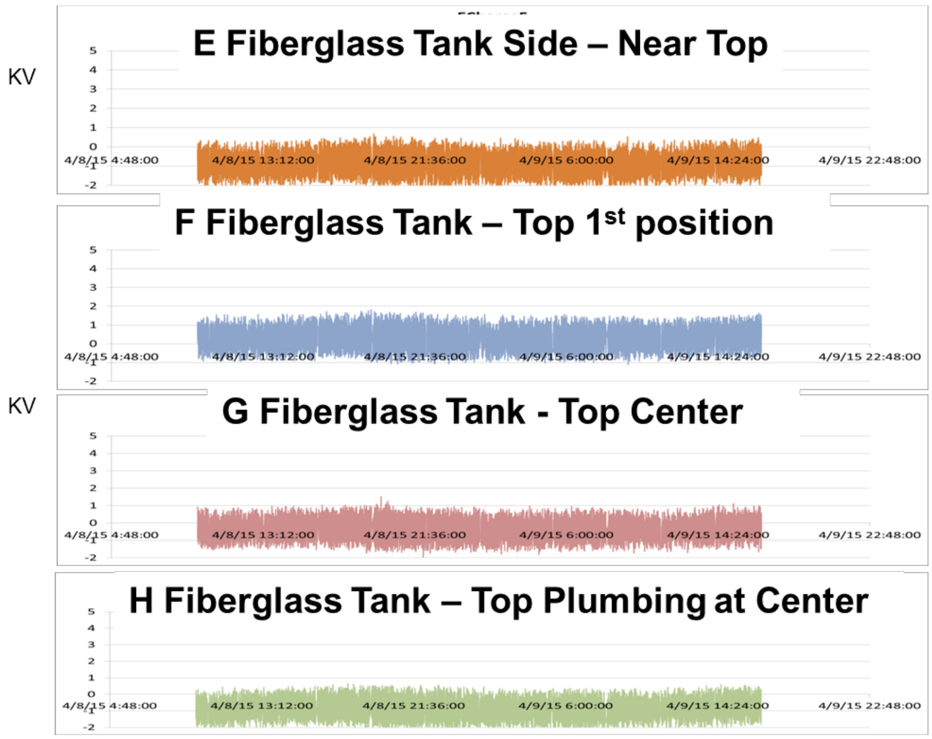

Fig. 5-20 Tank charge data; fair weather day (Part 2)

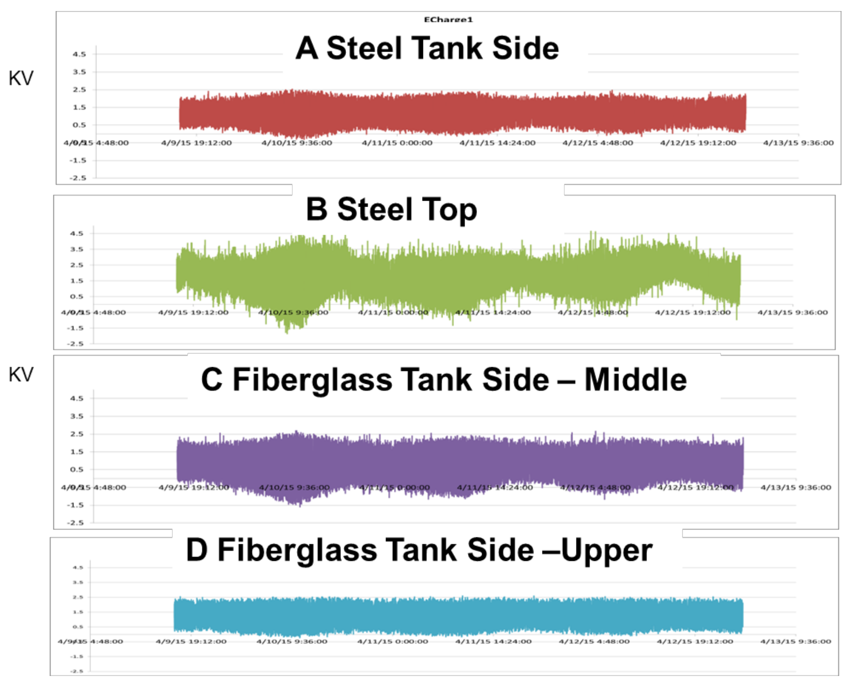

Fig. 5-21. Tank charge data; low intensity weather day (Part 1)

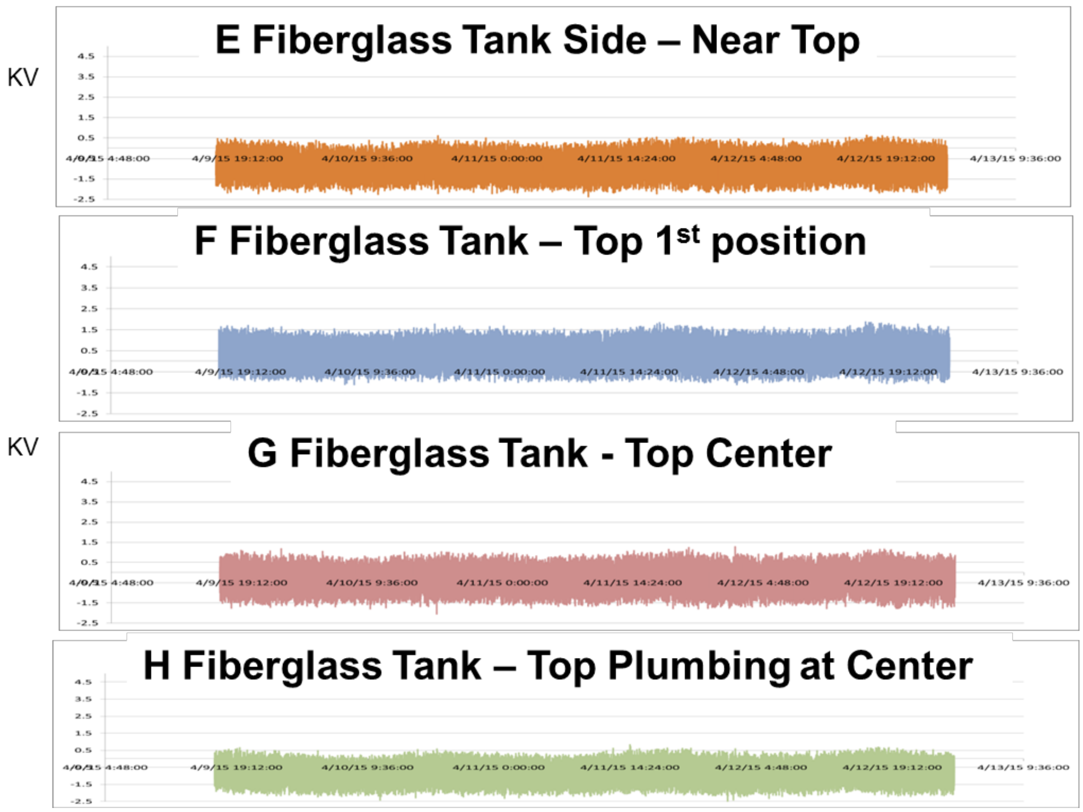

Fig. 5-22. Tank charge data; low intensity weather day (Part 2)

This minimal reaction to the moderate electrical activity could be associated with poor “pickup” locations or the possibility of poor induction from a weak storm passing too far from the battery tank to make a difference.

5.6 Potential risk reduction of system

The true value of a solution remains unappreciated until its operational and financial impact are realized. As was explained in the earlier sections of this chapter, the lightning in charge solution is capable of providing up to a 10 minute window of advanced warning prior to a lightning strike. In addition, tank charge sensors provide an extra dimension of operational input for fusion with atmospheric charge sensor data. This sensor combination provides a unique solution to operators of large hydrocarbon storage tanks.

Calculations and models presented in this section will equip project managers and decision makers with valuable tools for use in operations and planning. --- The tool tells a decision maker which sized tank to use in a specific lightning threat zone at a specific time in the life-cycle of a well (recall well decline curves) --- (young highly productive wells will get hit harder with shutdowns in operation)

Of course, the calculations must include the "cost" of the atmospheric charge and tank sensors as well as the benefit they provide to the IPL (Independent Protection Layers) that trigger the Nitrogen tank flood.

5.6.1 Cost of a lightning strike

The cost of battery tanks used in the industry are shown in the following plot (Fig. 5-23). The scatter plot also includes a trend line to enable future formulaic calculations. The idea here is to get a general trend line for purposes of calculations to help shape cost for lightning strikes. All costs are estimated to include removal of a lightning damaged tank, and cleanup. Then of course, the points also include delivery, taxes, complete instillation of a new tank.

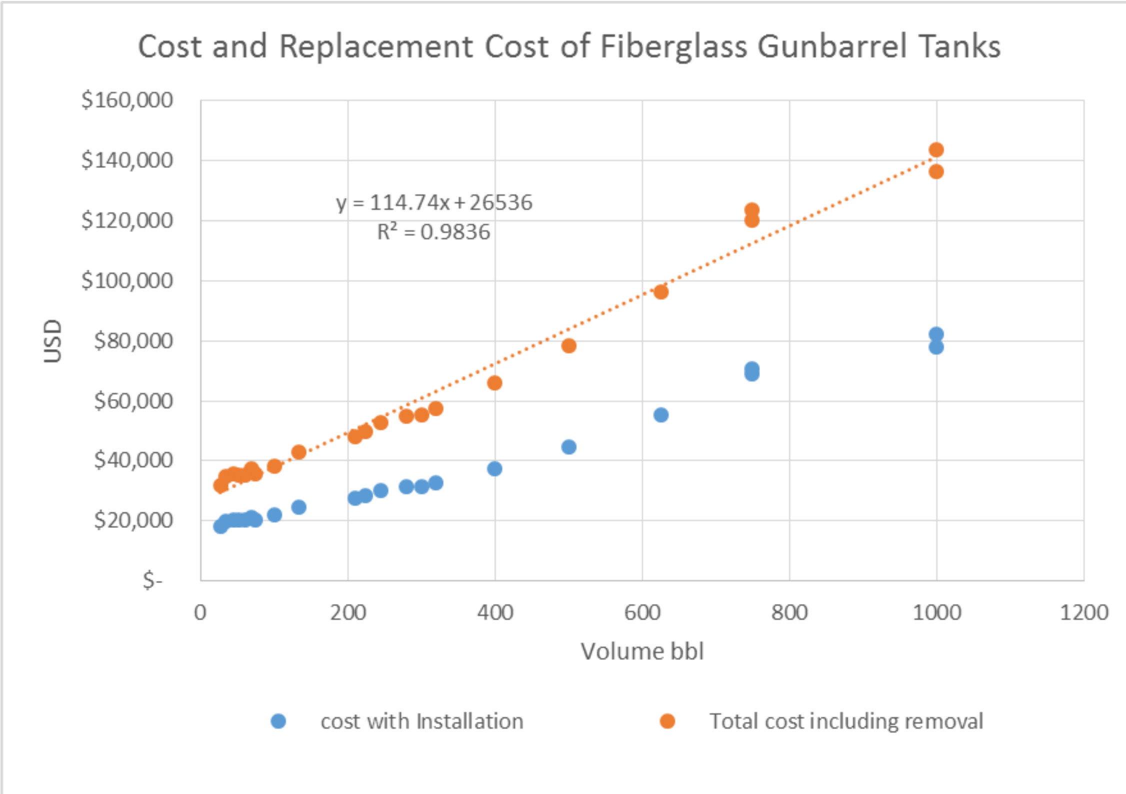

Fig. 5-23. Cost of replacing fiberglass gunbarrel tanks

As shown in Fig. 5-23, the replacement cost includes an estimate of cleaning up and removing an old tank following a lightning strike. However, it is difficult to know the extent of damage cause from the incident, for example additional tanks could have been impacts during the incident and substances such as Hydrogen Disulfide (H_2S) could have been released thus requiring additional environmental cleanup with hazardous material protective gear.

As was clearly explained in in Chapter 1, fracking is a process that expends a large amount of diverse chemicals. So, any lightning induced fire could cause unforeseen secondary spills in adjacent tanks. Exact costs associated with these incidences are difficult to quantify. In an attempt to bound the magnitude of the problem, a Monte Carlo simulation was run and the results are plotted in Fig. 5-24.

The simulation took 1000 what-if scenarios and simulated 33 accidents for a total of 33,000 calculations. The results of one of these sets of calculations is shown in Fig. 5-24. Each bar in the histogram, represents the magnitude of cleanup cost associated with a particular accident; the lower the number, the less complicated the cleanup and remediation costs.

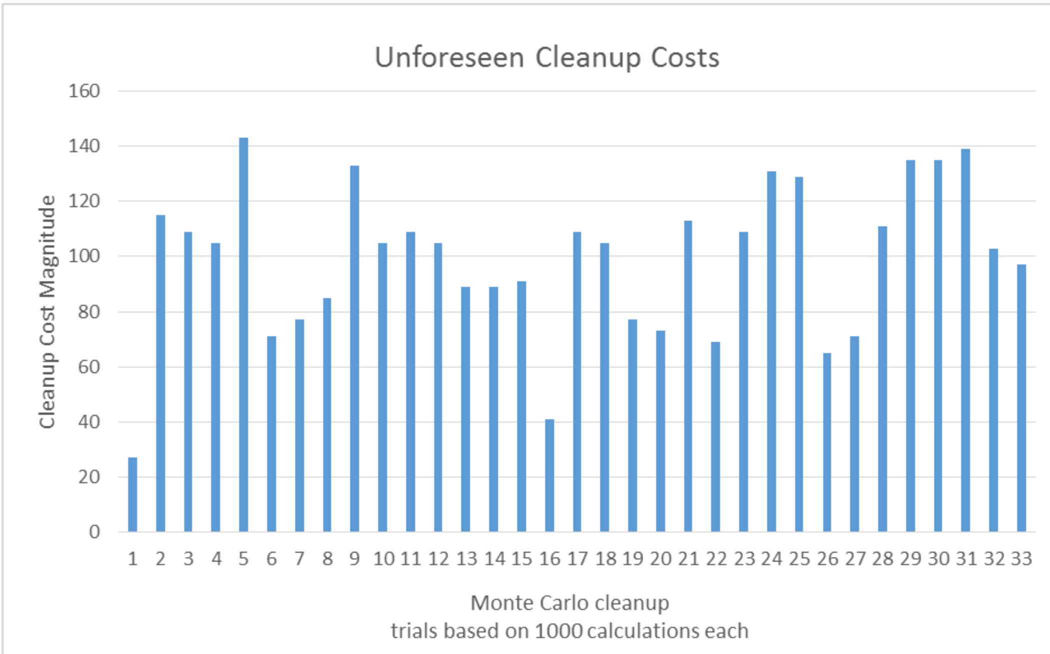

Fig. 5-24. Monte Carlo simulation of 33 accidents showing cleanup magnitude

The histogram shown in Fig. 5-24 is only concentrating on the magnitude of the cleanup process; there is no consideration of interruptions to operations and production. As was explained in Chapter 1 and shown in Fig. 5-25, fracking wells have a production profile over their 20-30 year life. Petroleum production experts including Dr. Michael Economides, a University of Huston Professor who have an understanding of the various production profiles (Hill et al., 2012). Fig. 5-25. shows examples of exponential decay with varying **instantaneous decline factors** (Hill et al., 2012).

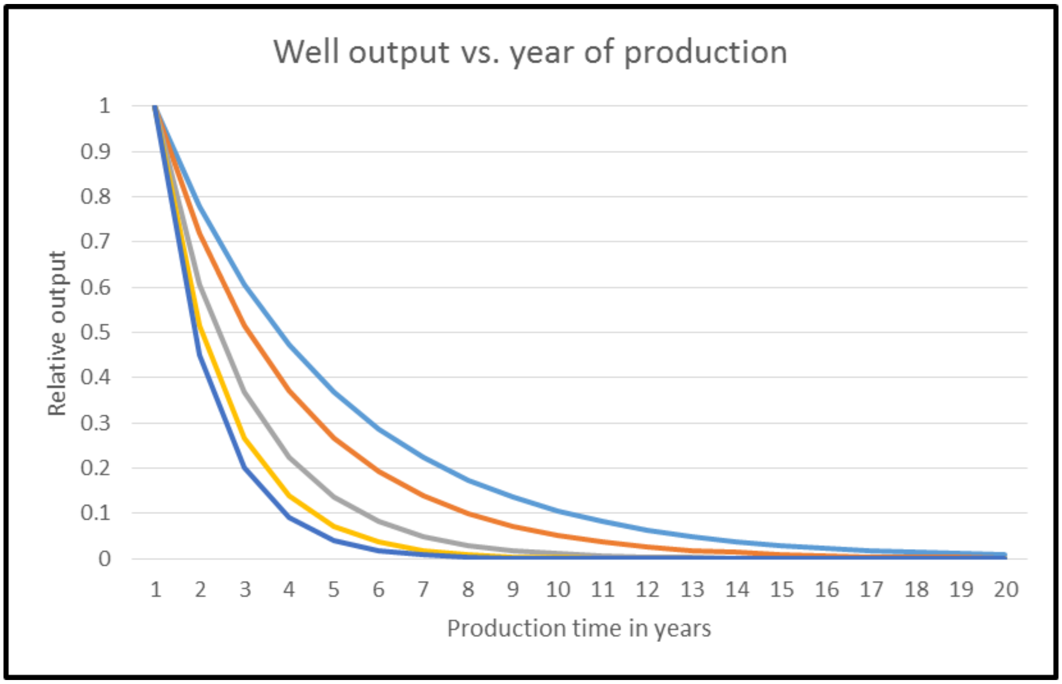

Fig. 5-25. Well profiles with various Instantaneous Decline Factors.

While Fig. 5-25. represents a very common well profile, other common decline curve functions enable the calculation of instantaneous production rate of wells; see Table 5-2.

Curve Type	Exponential	Harmonic	Hyperbolic
Instantaneous production rate at time t	$q(t) = q_i e^{-at}$	$q(t) = \dfrac{q_i}{1 + a_i t}$	$q(t) = \dfrac{q_i}{(1 + \frac{a_i t}{n})^n}$

Table. 5-2. Instantaneous production rates of wells (Hill et al., 2012).

In Table 5-2, the terms are defined as follows: q_i is the initial production rate, a and a_i are the instant decline and the initial decline rates respectively. Of course, t represents the production time in question. The variable n is simply equal to 1 in the harmonic case (and thus vanishes) whereas in the hyperbolic case n describes how a_i changes in the out years of production.

5.6.2 Implications to production

By knowing the production rate of a particular well, the implications of a lightning strike and thus associated risk to production stoppage[29] can be studied. As was explained in Chapter 1 & 2, a local battery is the hydrocarbon repository for 6-10 production wells. Given this reality, an impact to the battery will affect the production throughput of all other wells. Furthermore, as was shown in Fig. 5-25 and Table 5-2, wells exhibit production rates that can be expressed in closed form solutions. So, with this information, we can now examine the implication of a lightning strike on the battery resulting in a production stoppage at time “t” for an exponential well. First, we will make the valid assumption that the q_i for all wells supplying the battery is 1000 bbl per day; so, given the possibility of 6-10 wells feeding this battery, its through put rate is 6000-10000 bbl / day assuming maximum production. As a benchmark, in the Bakken region of Montana and North Dakota a fracked well that starts out producing 1000 bbl per day can decline by more than 70% by the start of the 3rd year of production (Tully, 2015). So from a management prospective, the production of fracked wells is heavily front loaded; any disruption to the production of a young well can have dramatic implications for production. We now translate these implications into an estimate of financial loss from the loss of crude oil to the fracking company. If the initial production rate of our wells under consideration was 1000 bbl per day and

[29] If a local battery is shutdown, production at 6-10 wells will completely stop.

we assume that 8 wells are feeding a battery impacted by lightning, what is the production loss profile of a battery assuming an exponential decay profile?

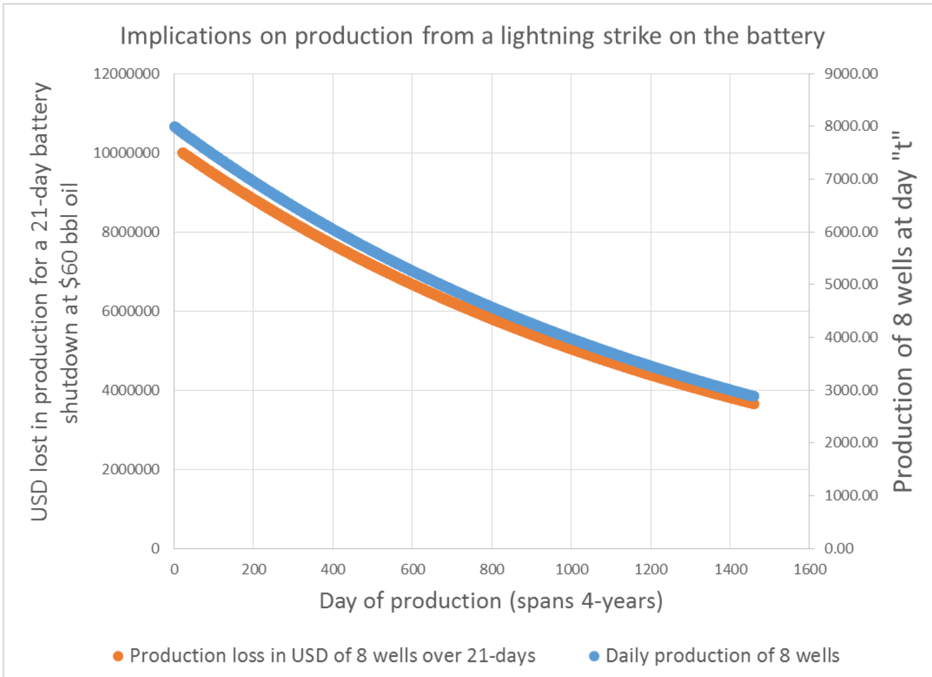

Fig. 5-26. Implications of a lightning strike to a battery

In Fig. 5-26, the implications of a lightning strike on a fracking battery quickly become apparent. If a lightning strike were to occur on day 365 of production, then the production loss over 21-days could amount to $7,747,650 with crude oil priced at $60 / bbl. Of course this is a raw number and does not factor in transportation of the product and equipment usage. However, labor is factored in since for companies like PXD, many employees are paid salaries since subcontracting is minimized. So, simply idling an otherwise productive well can be costly.

The key point to make with the plot shown in Fig. 5-26 is that loss to production from a lightning strike is highly dependent upon when it occurs in the lifecycle of a well. As an example, if we extend the same plot out and the lightning strike were to occur at 20-years in the lifecycle, the production loss would only be $61,000.

By compiling the concepts shown in Figs. 5-23 through 5-26, we can develop a relationship that shows the total loss from a lightning strike to a fracking battery (Eq. 5-3.)

$$\begin{aligned} &Loss\ in\ \$USD\ from\ a\ Lightining\ Strike \\ &\qquad = Production\ Loss + Equipment\ Loss\ and\ Replacement \\ &\qquad + Loss\ of\ Product + Lost\ worker\ productivity + Hazardous\ Cleanup \end{aligned}$$

Eq. 5-3. Financial Implications of a battery lightning strike

5.6.3 The lightning threat

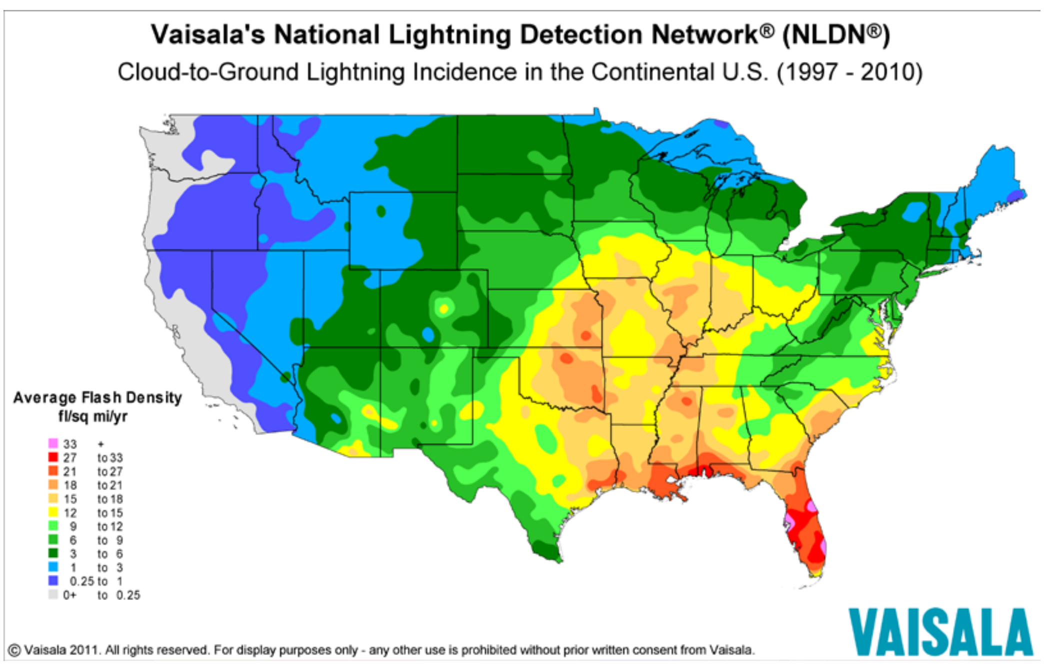

Fig. 5-27 Incidences of cloud-ground across the United States[30]

By reviewing Fig. 5-27, it becomes clear that the lightning threat is regional. Now the shale play map produced by the EIA is presented in Fig. 5-28 for study. Special note should be taken of current and prospective shale plays.

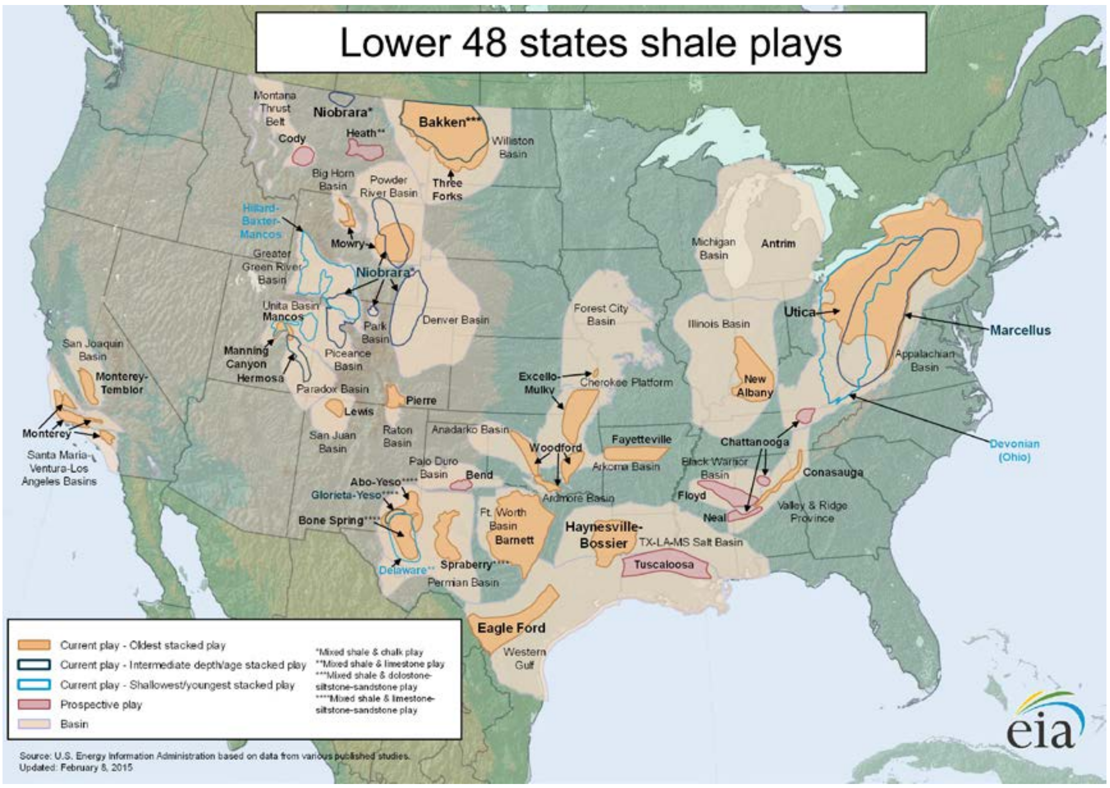

Fig. 5-28. Current and prospective U.S. shale plays in 2015 based on the EIA[31]

Fig. 5-29 is an overlay of Figs. 5-27 & 5-28, after examination it becomes apparent that could-ground lightning often occurs in regions with hydro fracking

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[30] http://www.vaisala.com/en/products/thunderstormandlightningdetectionsystems/Pages/NLDN.aspx

[31] U.S. Energy Information Administration (EIA) 2015 http://www.eia.gov/oil_gas/rpd/shale_gas.jpg

plays. Moreover, a closer inspection of Fig. 5-29 indicates that planned fracking plays in the Deep South closely align with the lightning threat. The superimposed maps solidify the case for lightning as a present and increasing threat for fracking (Fig. 5-29).

To complete the trifecta, a detailed study published in Science in 2014 by a Berkley research group indicates that due to global warming, calculations indicate a 50% increase in cloud-ground lightning events over this century (Romps et al., 2014). ---In light of these 3 factors, the implications are clear; lightning presents a credible and growing threat to the fracking industry.

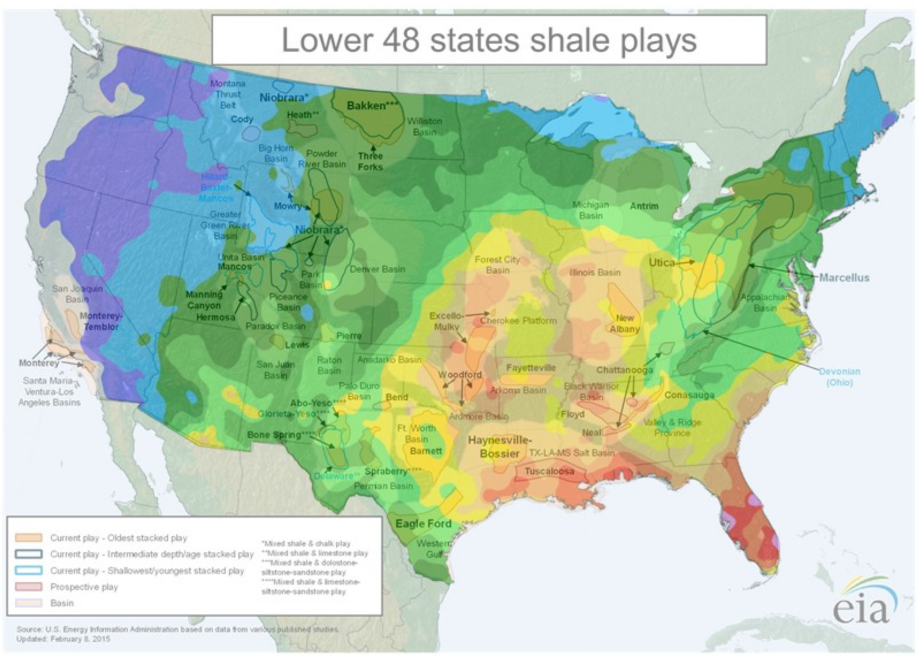

Fig. 5-29. Incidences of cloud-ground across the United States

While the lightning overlay looks attractive, there is also a methodology behind their construction. They are based on flash detection via an array of NOAA-NLDN[32] optical sensors; additional details are listed below.[33]

NLDN Network Specifications

- Thunderstorm detection efficiency in excess of 99%
- Flash detection efficiency greater than 95%
- Median location accuracy of 150-250m or better
- Network uptimes nearing 99.99%
- Data feed uptimes of better than 99.9%
- Event timing precision of 1 microsecond RMS
- Accurate peak current measurements
- Accurate cloud / cloud to ground classification

However, it is important to note that data from the NLDN is only available in raw from to U.S. Military and Government. The public has access to processed data that is often several months to a year old. For instance, this dissertation only includes Lightning data from Hatchett up until the end of 2014. --- So, the NLDN while sophisticated, does not provide raw data feeds in real-time to the public and is therefore limited in its utility for current storm events.

By inspecting Fig. 5-29 it becomes apparent that the Lightning threat is regional and obviously, fracking operations are stationary. So, for purposes of a

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[32] National Oceanic and Atmospheric Administration (NOAA); National Lightning Detection Network (NLDN)

[33]http://www.vaisala.com/en/products/thunderstormandlightningdetectionsystems/Pages/NLDN.aspx

credible threat to fracking operations, Lightning is a local concern. For calculation purposes, NOAA through its contractor VAISALA has a repository of Lightning strike data for regional areas going back to 1986. VAISALA calculates the number of cloud-ground lightning strikes per day and records this data in 4 km Albers Equal Area grids[34] that cover the Unites States.

My test site was Hatchett lease. The lease is a 340 acre area that housed several fracking wells and my test battery. The exact coordinates of the test site are 32.321953, -101.882291 by dropping these coordinates directly into the search box of NOAA's Service Weather Data Inventory site[35], Lightning strike data for a 25 sq. mile "tile" can be obtained; this very example is shown in Fig. 5-30.

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[34] Albers equal-area conic projection, is (named after Heinrich C. Albers), conic, equal area map projection that leverages 2 standard parallels or in our case 25 sq. mile tiles are used. http://en.wikipedia.org/wiki/Albers_projection

[35] http://www.ncdc.noaa.gov/swdi/#TileSearch

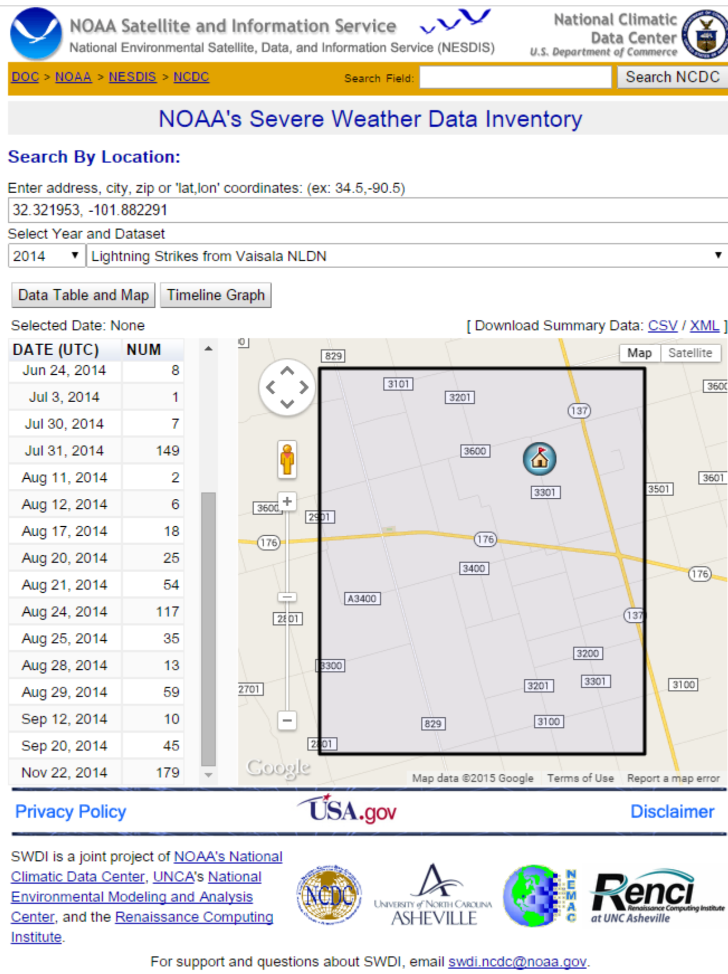

Fig. 5-30 Lightning strike data by day; Hatchett test battery

Knowing the historical Lightning activity just one year, is not entirely useful. Given this, I have complied daily Lightning activity for the Hatchett “tile” over the past 15 years. This information consisted 370 lightning event days with most days having more than one recorded lightning flash see Fig. 5-31. While the graph is detailed and seasonal patterns are clear, data in the format has limited use to answer our research questions posed in Chapter 2.

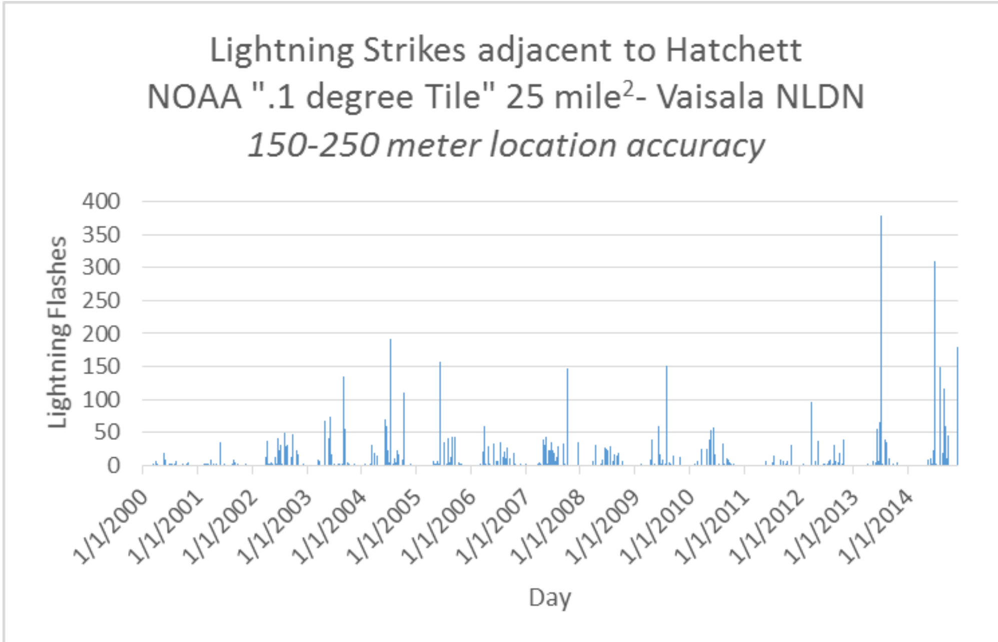

Fig. 5-31. Daily Lightning activity at Hatchett over 15 years

In order to answer our research questions, the data used to construct Fig. 5-31 must be modified to show the relative Lightning threat per month; knowing will be much more useful to a planner and operator. Indeed, this has been done in Fig. 5-32.

With the approach to understanding monthly totals, it is possible to develop a Lightning risk profile for the Hatchett location unique to a particular month. Obviously since this is the Southwestern United States, the warmer months of March – October have the most electrical storm activity. If we now glance back at Fig. 5-31, evidently, the ferocity of some electrical storms is profound while others are either far off in the distance or merely a whimper in comparison. Some storms in June exhibited more than 300 flashes while many others only registered in the single digits or even only 1 flash.

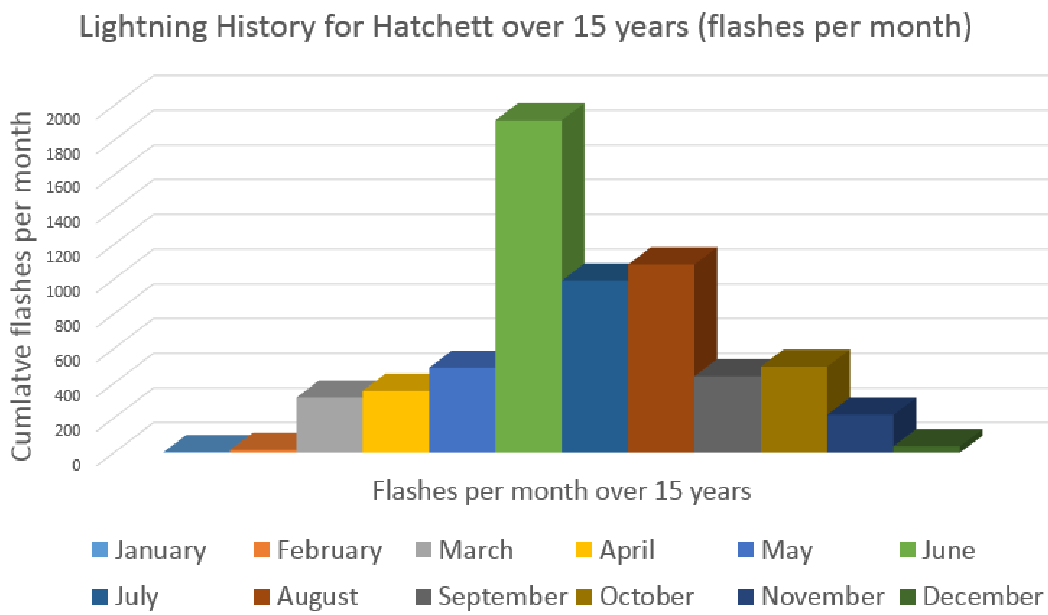

Fig. 5-32. Total flash counts at Hatchett per month over 15 years

Fig. 5-31. Is quite revealing; over a 15-year period, the months have large viabilities in electrical storm activity. Moreover, some days in the most energetic month of June might only have 1-5 flashes where some notable days has over 300. The key point here is that while as expected, March – October have the most electrical storm activity, assigning an average for a particular month while useful, does not provide the whole picture. Figure 5-31 provides more useful information that will be used to calculate monthly Lightning risk in section 5.6.

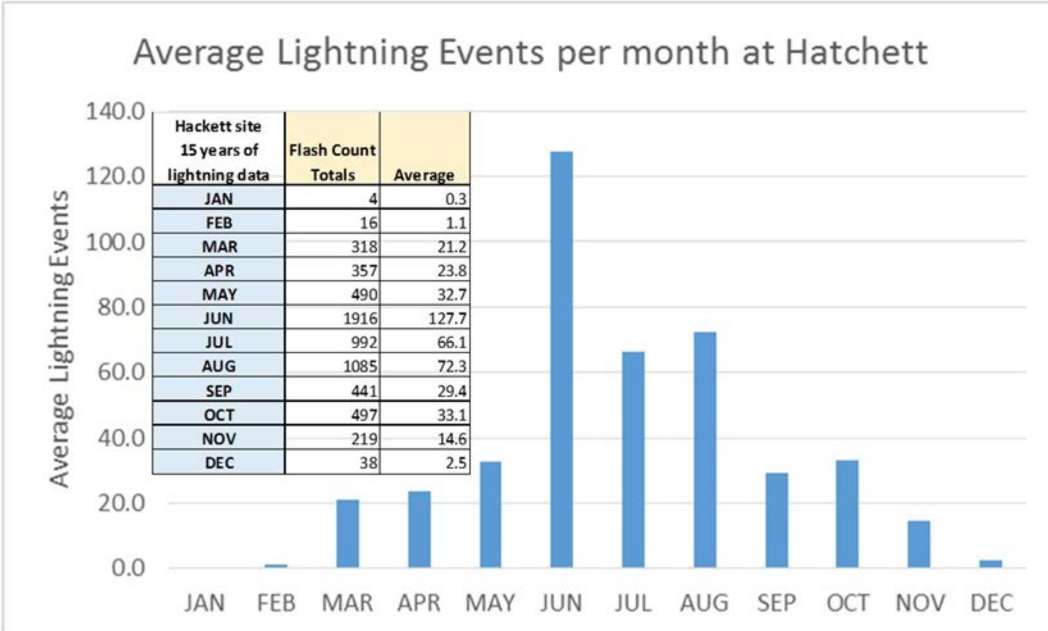

Fig. 5-33. Average lightning events per month at Hatchett

Table 5-3 shows the monthly average Lightning flashes per month over a 15 year period for Hatchett. The standard deviation varies greatly between months and most notably is largest in the peak months of lightning activity. Fig. 5-34 helps to display this dramatic level of difference in storm intensity; it is not surprising that the standard deviation is high in these months. --- The month of November has the highest, but this is due to the very small storm count, and the skewing properties of one single strong storm.

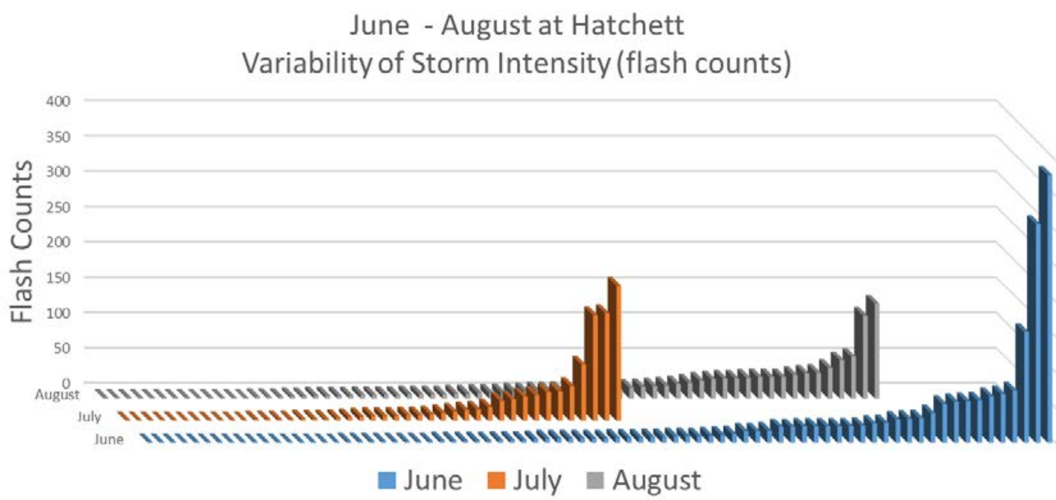

Fig. 5-34. Flash counts of storm events during peak months over 15 years

If we make the reasonable assumption that most thunderstorms in the Midland, TX area (near Hatchett) pass at similar speeds, then logically more electrical activity is concentrated in the same block of time for the active summer months.

Hackett site 15 years of lightning data	Flash Count	Average	Standard Deviation
JAN	4	1.3	0.6
FEB	16	2.3	2.1
MAR	318	14.5	22.8
APR	357	15.5	18.7
MAY	490	10.2	13.4
JUN	1916	24.6	57.9
JUL	992	23.1	42.7
AUG	1085	16.2	23.5
SEP	441	11.9	32.1
OCT	497	16.0	32.1
NOV	219	31.3	66.0
DEC	38	12.7	20.2
Average	531.1	15.0	27.7

Table 5-3. Average and Standard Deviation

Thus, in the stronger storms of the summer, more lightning risk is compressed in the same block of time. So, risk follows this pattern and is concentrated more in the summer months. Any mitigation strategy through and IPL (Independent Protection Layer) will have the greatest risk mitigation vs. cost benefit in these highly active months. A mitigation strategy will be discussed in section 5.7 that will account for this reality.

5.6.4 Risk and costing it all out

As was described in detail in section 5.4.1, the cost to a nominal 8 well fracking operation could amount to $7,747,650 from the temporary shutdown of the battery and subsequent production disruptions. Of course, that is not the totally potential financial losses; we now revisit Eq. 5-3 and now build Table 5-4 for a more complete picture of cost.

	USD	Comments
Production Loss	$ 7,747,650	Section 5.4.1 and Fig. 5-13
Equipment Loss and Replacement	$ 83,906	Fig 5-10, y=114.74X + 26536; assume 500 bbl tank
Loss of Product	$ 30,000	assume $60 / bbl and 500 bbl tank
Hazardous Cleanup	$ 99,000	Average cleanup cost based on 33,000 Monte Carlo simulated tank accidents; Fig. 5-11.
Public relations; reputation; added regulation?	Unknown?	BP is still paying for a 5 year old disaster today; they "will make it right"
TOTAL potential cost of Lightning Battery Strike	**$ 7,960,556**	

Table 5-4. Potential cost of a Lightning strike at day of 365 production

Most costs in Table 5-4 depend upon basic calculations that can be backed up in an easily explainable manner. The public relations, reputation, and in turn the potential for added regulation costs are mostly beyond the scope of this dissertation. With that said, for a large company with a brand to protect, along with the persistent gaze of regulators and the "frack no" public, the costs could exceed the production loss. In relation to the the BP Deepwater Horizon spill, besides 14.3 Billion in cleanup costs (Gilbert, 2014), another consequence of the disaster hit BP at the pump with a 26% loss in profit margins following the oil spill (Barrage et al., 2014). From the standpoint of environmental fines alone, a judge in a 2014 court decision imposed a $4,300 per barrel of crude spilled under the Clean Water Act which equates to $18 Billion USD (Gilbert, 2014).

Spill Spend

Under Thursday's ruling BP faces up to $18 billion in Clean Water Act penalties.

BP so far had set aside $3.5 billion.

Amount BP has spent/set aside, in billions	
Litigation and settlement costs	$25.87
Spill response costs	$14.30
Clean Water Act penalties	$3.51
Environmental costs	$3.03
Other Costs	$1.94
	$48.65
Recoveries	($5.68)
TOTAL	**$42.97**

Source: the company

Data as of second quarter 2014.

The Wall Street Journal

Fig 5-35. Current cost of BP Deepwater Horizon oil spill (Q2 2014) (Gilbert, 2014).

5.6.5 Direct Lightning strike and charge induction risks

As Chang et al. outlines, the direct lightning strike zone is between 100 and 10 m and out of 80 Lightning tank accidents studied, 12 tanks were impacts in this manner resulting in obliteration (Chang and Lin, 2006). For example a refinery tank was hit with a direct strike in October of 1995 resulting in $50 million (2015 USD) in property damages. --- It took 20 months for the refinery to recover to full production.

While direct strikes are dramatic, a more sinister threat is tank charge induction. The massive charge energy from an electrical storm has an induction footprint of 15 to 150 sq km. Thus, from a probability prospective, the charge induction threat is of significant concern.

For our calculations, we will make the reasonable assumption that 90% of the NLDN flashes recorded are within the 15 to 150 sq km window since our "tile" is 25 sq. miles

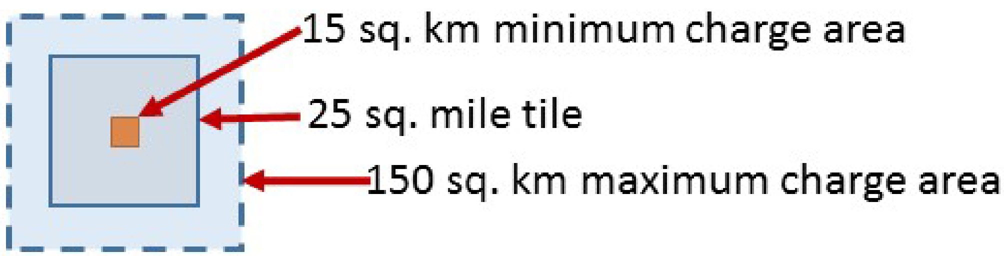

Fig. 5-36 Charge induction area according to Chang et al. (Chang and Lin, 2006) in relation to our tile

Given this simple overlay of charge induction upon our NLDN tile, through simple geometric calculations, at least 76% of the NLDN recorded flashes are within the charge induction zone. For example, if we use the values shown in Table 5-3, then for the month of July, part of the 25 square mile tile will be under the induction zone 17 times. We now generate a table to show the average number of induction zone days for each month at Hatchett (Table 5-5). This simply show then number of times per a given month (on average) that we can expect our tile to be under the induction zone.

Hatchett site 15 years of lightning data	Average lightning event count	Induction zone events per month over the tile
JAN	0.3	0.2
FEB	1.1	0.8
MAR	21.2	16.1
APR	23.8	18.1
MAY	32.7	24.8
JUN	127.7	97.1
JUL	66.1	50.3
AUG	72.3	55.0
SEP	29.4	22.3
OCT	33.1	25.2
NOV	14.6	11.1
DEC	2.5	1.9

Table 5-5. Average number of induction zone events per month

At the beginning of this section, we note that a direct strike radius has a damage reach of up to 100 m which is the same as 31,416 sq. meters or 0.0314 sq. km. Given that the area of a battery is conveniently around this area, our calculation would appear simple; however, there are many storage batteries in a 25 sq mile tile. For instance, it is easy to count 30 such storage batteries surrounding the Hatchett site. However, we step back and look at just 1 tank; a general equation for the probability of a direct strike on any tank in the tile is shown in Eq. 5-2.

$$P = \frac{Strike\ Zone * Avg\ Lightning\ counts\ in\ month}{Tile\ size}$$

Eq. 5-4 Probability of a direct lightning strike; given month and site

By taking Eq. 5-4 and inserting our values shown in Table 5-5., we are able to generate Table 5-6 which shows the risk of a direct battery strike in a given month at

Hatchett. --- keeping mind that this is for only one battery. As was previously stated, the 25 sq. km tile area has several battery facilities.

Hackett site 15 years of lightning data	Average	Probability of 1 battery being in the strike zone during the month
JAN	0.3	0.0001
FEB	1.1	0.0005
MAR	21.2	0.0103
APR	23.8	0.0115
MAY	32.7	0.0158
JUN	127.7	0.0619
JUL	66.1	0.0321
AUG	72.3	0.0351
SEP	29.4	0.0143
OCT	33.1	0.0161
NOV	14.6	0.0071
DEC	2.5	0.0012

Table 5-6. Probability of a one battery strike on a battery at Hatchett

By assuming that all direct strikes result in deviation, the balance of our calculations will be show a potential worst case scenario for a fracking operator such as PXD.

5.6.6 Summary Costs

The $7,960,556 number from Table 5-4 will now be revisited. With that value in mind, a financial risk exposure table will now be calculated with the values in Table 5-6 to give us Table 5-7.

Hatchett site 15 years of lightning data	Average	Probability of 1 battery being in the strike zone during the month	Cost of exposure to lighting risk (Direct Strike)
JAN	0.3	0.0001	$ 1,029.44
FEB	1.1	0.0005	$ 4,117.77
MAR	21.2	0.0103	$ 81,840.66
APR	23.8	0.0115	$ 91,877.73
MAY	32.7	0.0158	$ 126,106.68
JUN	127.7	0.0619	$ 493,102.86
JUL	66.1	0.0321	$ 255,301.69
AUG	72.3	0.0351	$ 279,236.22
SEP	29.4	0.0143	$ 113,496.01
OCT	33.1	0.0161	$ 127,908.21
NOV	14.6	0.0071	$ 56,361.97
DEC	2.5	0.0012	$ 9,779.70
		TOTAL	**$ 1,640,158.94**

Table 5-7. Cost of direct strike risk for 1 battery at Hatchett

So, the cost of risk exposure varies greatly between seasons. As such, a 365 day operating schedule for a mitigation system makes little economic sense. For example, months December – February could be used for system maintenance.

For a final cost basis, our mitigation system cannot exceed $1,640,000 in annual expenses including amortized CAPEX and ongoing maintenance. As was previously stated, this risk exposure cost is for only on battery. If the final lightening mitigation IPL and system can cover multiple batteries with limited additional cost, then it would be highly valued.

5.7 Lightning impact mitigation and the application to industry

Real-time prediction of possible Lightning events at the battery is of limited value if there is no mitigation strategy. In this section, we present a mitigation strategy and the associated IPLs. Furthermore, I will show how triggered IPLs will introduce Nitrogen flooding for lightning impact mitigation.

IPLs were detailed in sections 2.1.2 and 2.1.3 under the guise of Fire and Gas Safety systems (FGS) and Emergency Shut Down (ESD)[36]. Within these sections, design standards for these systems were described and summarized in Table 2-5. The IPL and mitigation solution presented herein follows portions of the IEC 61511-2 standard. The lightning strike preparation and mitigation strategy to be described parallels the functionality of a FGS and EDS system as was shown Figs. 2-8 and 2-9. and shown here again for purposes of discussion. As was described in sections 2.1.2 and 2.1.3, both FGS and EDS systems are widely deployed in industrial settings and built upon the rigger of the IEC 61511 standard.

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[36] By convention, Shutdown is broken into two separate words to follow the acronym

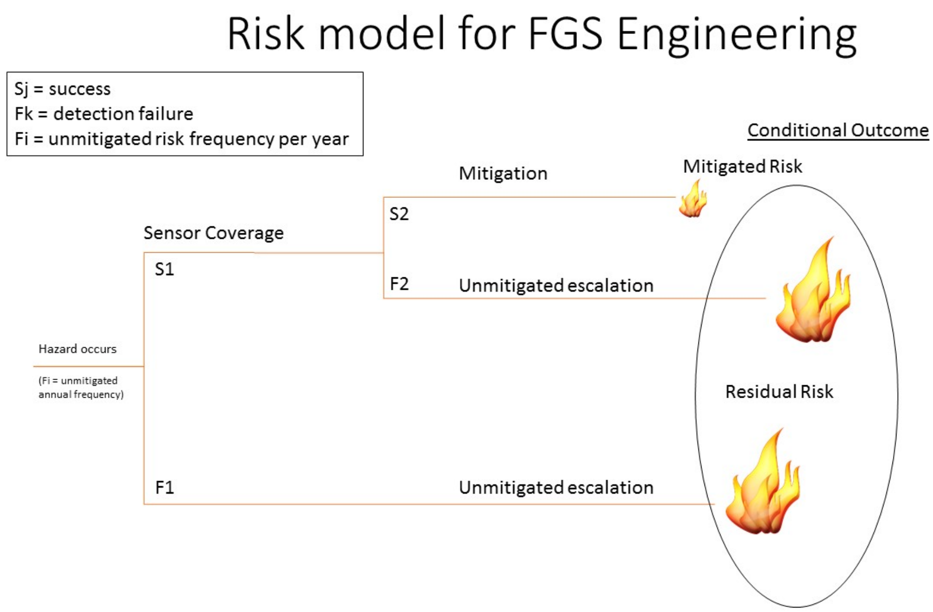

Fig. 5-37. Modeling risk in FGS systems (Kenexis, 2013).

"An alarm system can be used as a method of risk reduction by reducing the demand rate on the SIS[37] providing:

- the sensor used for the alarm system is not used for control purposes where loss of control would lead to a demand on the SIF[38];
- the sensor used for the alarm system is not used as part of the SIS; (Instrumentation, 2004)

When deciding if risk reduction is required, it becomes necessary to establish safety and environmental targets. These targets might be aligned to a certain site or operator and will be compared to the level of risk without additional safety functions.

[37] Safety Instrumented System
[38] Safety Instrumented Function

Once the need for risk reduction is established, it becomes necessary to identify the required functions that mitigate and return to a safe state. The functions may be described in generic terms without details to particular technologies (this will be relegated to IEC 61508; see Table 2-5).

For alignment with IEC 61511, the hazard and risk analysis should consider the following:

- “each determined hazardous event and the event sequences that contribute to it;”
- “the consequences and likelihood of the event sequences with which each hazardous event is associated; these may be expressed quantitatively or qualitatively;”
- “the measures taken to reduce or remove hazards and risks;”
- “the assumptions made during the analysis of the risks, including the estimated demand rates and equipment failure rates; any credit taken for operational constraints or human intervention should be detailed;”(Instrumentation, 2004)

The IEC 61511 clearly states that designing an architecture is an iterative process and designs will change as more details become available (Instrumentation, 2004).

5.7.1 Nitrogen flooding for mitigation

Nitrogen is an inert gas that displaces oxygen from the combustion triangle (Fig. 1-16). By following IEC 61511, for the design of a proposed mitigation strategy, it is known that a signal from the decision and fusion engine with inputs from atmospheric charge and tank charge sensors will trigger the IPL (see Chapter 4 for details on sensors and fusion). By reviewing Fig. 5-37 and considering Fig. 5-38, the description of the Nitrogen mitigation solution will become more apparent.

Fi*(F1+S1*F2) = Residual Risk (per unit time)
Fi*(S1*S2) = Mitigated Risk (per unit time)
S1*S2 = “Lightning Mitigation Effectiveness”

Fig. 5-38. IPL equations

If we assign realistic probabilities of 80% effectiveness or **0.20 to S1** (tank charge sensor) and 90% effectiveness or **0.10 to S2** (atmospheric charge sensor), we can calculate the combined effectiveness of our IPL(s). The term “Fi” is simply the probability of the event occurring if there is no protection. --- So without completing the calculation, it is easy to see that an IPL configuration will help to mitigate almost all of the Lightning induced fire threat.

This works well in equation form, but how would it work in the field? Or by extension other hydrocarbon storage facilities such as large jet fuel storage centers or oil refineries?

The most likely method is to have a centrally located source of Liquid Nitrogen with evaporators. Ubiquitous poly-ethylene tubing could transfer nitrogen to all batteries within a reasonable distance.

Since sensor information from one atmospheric charge sensor can cover several square miles of area, several batteries can be monitored with only one atmospheric sensor. Even more importantly, a more advanced system can leverage sensor fusion methodologies (described in Chapter 4) to setup voting between sensors including tank charge sensors and other atmospheric sensors.

In the proceeding sections of Chapter 5, many foundational calculations were made describing the lightning threat at the Hatchett site. In addition, lightning threats and trends for the future were also presented. The culmination of many of the calculations is shown in Table 5-8. It is important to note that “A” was calculated based on consideration of unmitigated risk and sensor performance. Following this, column “B” considered the cost of a battery strike ($7,960,556 from Table 5-4) in light of results from column “A”.

			A	B
Hatchett site 15 years of lightning data	Average	Unmitigated risk - Probability of 1 battery being in the strike zone during the month	Fi*(F1+S1*F2) Residual Risk per month	Residual Risk Cost following Nirtogen Mitigation
JAN	0.3	0.0001	0.00004	$ 288.24
FEB	1.1	0.0005	0.00014	$ 1,152.98
MAR	21.2	0.0103	0.00288	$ 22,915.39
APR	23.8	0.0115	0.00323	$ 25,725.76
MAY	32.7	0.0158	0.00444	$ 35,309.87
JUN	127.7	0.0619	0.01734	$ 138,068.80
JUL	66.1	0.0321	0.00898	$ 71,484.47
AUG	72.3	0.0351	0.00982	$ 78,186.14
SEP	29.4	0.0143	0.00399	$ 31,778.88
OCT	33.1	0.0161	0.00450	$ 35,814.30
NOV	14.6	0.0071	0.00198	$ 15,781.35
DEC	2.5	0.0012	0.00034	$ 2,738.32
				$ 459,244.50

Table 5-8. Residual risk cost after mitigation

Loss from 1 lightning strike including all presented factors	Mitigation solution reduces annualize risk cost to…
$10 million per direct strike	**$459,000 per tank** **Saves the fracking industry close to $1.2 million in annual risk cost exposure per battery tank**

Table 5-9. Bottom-line impact of mitigation solution

5.7.2 Proposed architecture and costs

Development of an architecture must consider the operational constraints of such a system also with considerations for cost. As was previously outlined in section 5.6.3, the lightning risk follows seasonal patterns. However, the intensity of storms and their associated durations varies significantly; this is particularly true in the summer months. Any proposed solution must account for this operationally reality. An architecture is now presented which will allow for long periods of dynamic nitrogen flooding of hydrocarbon tanks during high lightning risk days while also seamlessly functioning in low event days; see Fig. 5-39.

Take note of Fig. 5-17; trigger thresholds are set at the absolute value of 1000 V/m^2 for a charge on the EFM sensor. Once this threshold (established by NASA for its Launch Pad Lightning Warning System - LPLWS) is crossed the system shown in Fig. 5-39 will be activated.

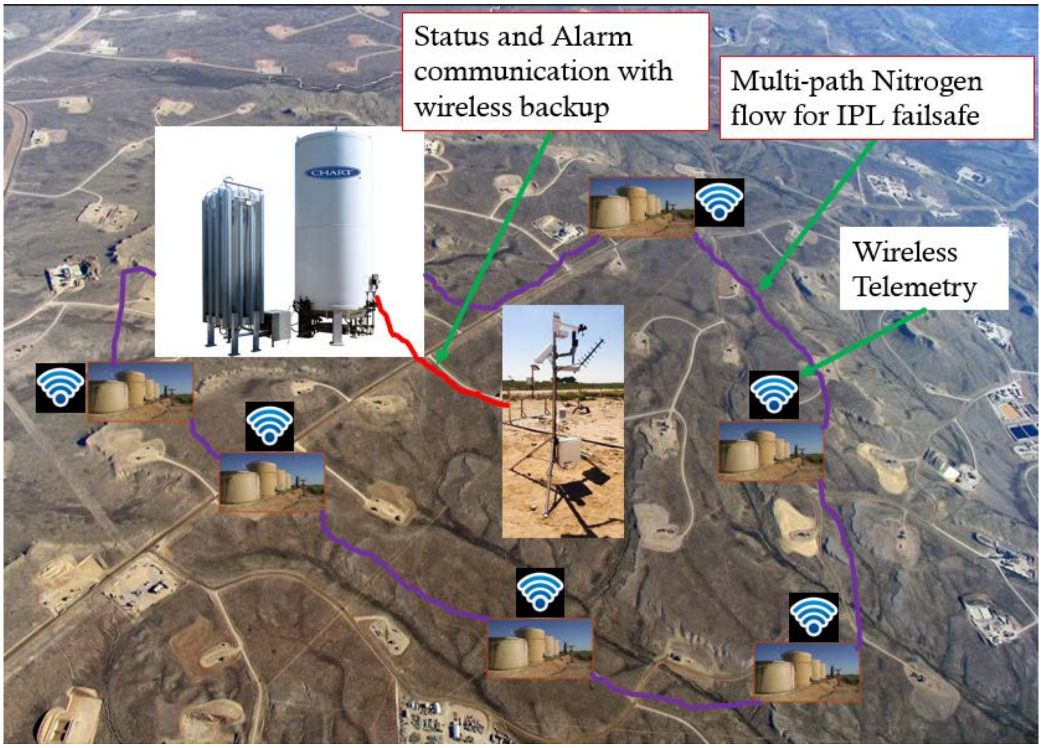

Fig. 5-39. Architecture for Mitigative solution

Once a predetermined lighting risk threshold is crossed, a signal is sent from the EFM sensor station to a centrally located nitrogen source. In Fig. 5-39, liquid nitrogen is shown, but the nitrogen could simply be compressed gas. In the latter case, nitrogen loss due to storage alone would be eliminated. Cryogenic storage tanks such as Liquid Nitrogen tanks are given a NER% rating for storage efficiency. In general, the larger the tank, the less percent is loss to static evaporation alone; a typical NER% rating is 1.5[39] where NER stands for the daily Normal Evaporation Rate in % per day at 70 degrees Fahrenheit and 1 atmosphere of pressure. Ideally, this value of 1.5% NER should be considered when calculating the cost of a liquid nitrogen vs. compressed nitrogen solution. One should note that delivered liquid

[39] http://www.cyl-tec.com/docs/liquid_cylinder_owners_manual.pdf

nitrogen costs range from $0.06 - $0.10 USD per liter; this cost depends greatly on the location for delivery.

For calculations herein, the cost of $0.10 USD per liter will be considered which equates to the same cost for 1500 liters of nitrogen gas when evaporated at Standard Temperature and Pressure. It is assumed that the 500 bbl hydrocarbon storage battery tanks are 75% full on average; the presented nitrogen mitigation solution will be required to displace 125 bbl of headspace with nitrogen gas per system activation event. As was explained earlier, 1 bbl is 42 U.S. Gallons or 159.6 letters; thereby giving us a headspace volume of 159.6 liters for the 4 hydrocarbon battery tanks at Hatchett. An additional assumption is that nitrogen gas will purge rapidly upon initial activation and then slowly during the munities surrounding triggering events; this will result in nitrogen consumption amounting to 10 times this volume or 1596 liters. As explained earlier in this section, that volume of gaseous nitrogen would expend about 1 liter of LN2 (liquid nitrogen) amounting to an expense of $.10 USD. More importantly, as indicated in Table 5-3, the average monthly lighting flash count over a 15 year period for Hatchett is 15. We will assume that each of these flashes activates the mitigation solution. Thus, the monthly liquid nitrogen consumption will be 15 liters per battery or 150 liters for 10 batteries. At $1.50 per liter including delivery, this amounts to a $225 monthly expense for LN2 for lightning mitigation alone. There will be more monthly nitrogen loss due to a NER% per day of 1.5 than consumed in say a 500 liter LN2 tank. Specifically, 182 liters per month amounting to $273 worth of LN2 per month. Thus, the total expenditures for LN2 per month for both mitigation and NER is $498.

An alternative solution is to have compressed nitrogen cylinders at each of 10 hydrocarbon batteries resulting in no NER since by definition, there is no evaporative loss. Plus there is no CAPEX for the instillation of long runs of polyethylene tubing. Each battery would receive alarm and signaling information from the EFM station via the wireless telemetry link. Pricing for compressed nitrogen gas cylinders with delivery is about $.30 per cubic foot which is $.01 per liter. By using the same logic in relation to the number of triggering events shown earlier in this section, there will be 22,500 liters on average of nitrogen gas consumed per battery per month at Hatchett. For expense purposes, this equates to 795 cubic feet or $239 per month.

In summary, the CAPX for the liquid nitrogen based solution is $405,000 including an LN2 orca for storage along with polyethylene tubing. Whereas the CAPEX can be minimized to only $105,000 for a compressed nitrogen solution since no polyethylene runs are required. The monthly operational expenditures for the LN2 solution are $3637 and the compressed nitrogen solution is $3378.

By equating all this information to daily dollar values, and plotting them in Fig. 5-40, it becomes apparent that the daily expense for both the LN2 and compressed nitrogen solutions are far below the value of the crude oil produced; even at year 20 of production. The driving factors in making a decision are the CAPEX for both solutions presented earlier in this section. The plot clearly shows that the solution remains viable even in the out years of production.

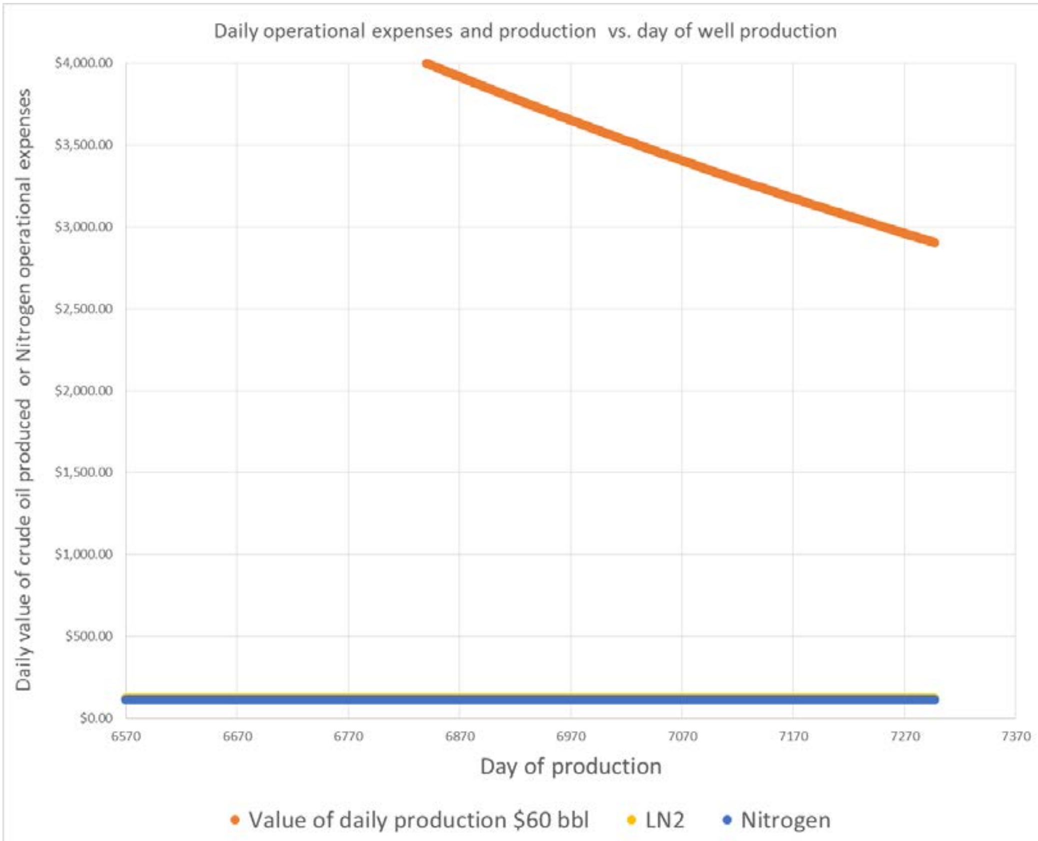

Fig. 5-40. Daily value of production for 8 wells vs. daily cost of LN2 and nitrogen mitigation solutions.

Thus, the basic concept of this architecture for lighting mitigation in the fracking environment is a viable solution from an economic prospective.

5.8 Summary

In chapter 5, I answered the first 2 research questions posed in Chapter 2 by applying the methodologies discussed in Chapter 4. I didn't see this at all. Now I am skim reading the document. But you need to call out explicitly something like:

Research Question 1 posed in Chapter 2 read as follows: Is there a way to use sensors and modeling to help minimize the financial and environmental losses and issues? If so, could it be automated?

This family of questions has been answered through the assessment of risk cost basis thought this chapter. My mitigation solution was clearly shown to reduce the annualized risk cost basis for an operating fracking well (Table 5-8) In addition, fundamental equations were presented that govern the automation of IPL mitigation systems (Fig 5-36) These equations were present in the context of standards including IEC 61511 in preparation for automation and validation.

In order to answer this fundamental question, a number of associated questions must be answered, including:

2.) Develop the driving equations of the intersecting items, such as:

- probability of lightning strikes,
- cost of an environmental incident (pollutant dependent)
- well production estimation (temporal dependent)
- cost to incumbent organization for an incident (cost to fracking company)

Question 2 was answered in within chapter 5 as follows. The probability of a lightning strike was examined in detail in section 5.6.3. The cost of an environmental incident from pollution was estimated in Fig. 5-24 and a large scale example was shown in

Fig. 5-35 which extends to a $2.15 million by using the same logic on a 500 bbl battery tank. Well production estimates based on the age of the well was presented in Section 5.6.2. Plus, the cost of an unmitigated direct strike on a tank was discussed in Section 5.6.4

***** If implemented, in a functional IPL mitigation system, these answers will save the hydro fracking industry $1.64 million in risk cost exposure per battery tank in the Midland lightning risk zone (Table 5-7). *****

Lightning has been a documented threat to hydrocarbon storage facilities for over 100 years. There have been no disruptive solutions presented or implemented to remove Lightning as a concern. A detailed study by Chang shows that 33% of 241 tank accidents were caused by lightning (Chang and Lin, 2006).

As was detailed in Chapter 2, researchers have concluded that cloud-ground Lightning strikes are likely to increase by 50% over the current decade due to global warming (Romps et al., 2014) Furthermore, the combination of Lightning risk maps (NOAA) and prospective shale plays (EIA) shown in Chapter 2 help highlight the importance of Lightning risk mitigation for the future of hydro fracking operations.

My methodology can be extend to other Lightning threat areas and even other processes and facilities beyond hydro fracking. This research work has carved a path forward for the integration of sensors in safety critical systems (SCS) for hydro fracking and storage facilities. This contribution to the body of knowledge along with the broader implications that will be explored further in Chapter 6 will serve as a springboard for follow-on research by others.

5.8.1 Risk conclusions and mitigation

A direct strike on a battery tank can be devastating both financially and environmentally. The probabilities of such an occurrence – as presented in this chapter - are sobering. Without a lightning effect mitigation system for hydrocarbon storage systems, tank fires and chemical spillages will continue in hydrocarbon storage tanks costing operators millions or in some cases billions of dollars.

Chapter 6: Conclusions and Recommendations

6.1 Research Summary

Lightning has stood as an unresolved threat to hydrocarbon storage facilities for over 100 years. Literature research has shown that 33% of all modern hydrocarbon tank accidents are due to lightning (Chang and Lin, 2006); in addition, cloud-ground lightning strikes are predicted to increase by 50% this century (Romps et al., 2014). An overlay of the current National Lightning Detection Network (NLDN) risk map and the Energy Information Administration shale play map clearly show the lightning threat only increasing with the migration of future shale activities. While planning may change, shale deposits and regional lightning threats are not changing geographically; this research quantifies the threat and outlines clear lightning mitigation strategies.

Furthermore, real-time detection and the associated methodology of lightning mitigation have implications for industries far beyond hydro fracking. By leveraging industrial standards for Fire and Gas Systems (FGS) such as IEC 61511, the proposed lightning effects mitigation system has a pathway toward verification and eventual validation at a broad array of industrial sites. Some extended applications included Navy fuel storage depots and Liquefied Natural Gas (LNG) facilities as shown in Fig. 6-1.

Recommendations include the deployment of Lightning and charge sensor systems at candidate sites for completion of the V&V[40] process through operational system verification of software and hardware with IEC 61508 and ANSI/ISA S84.

6.2 Conclusions

I have concluded that a lightning strike on a hydro fracking battery has the potential to cause $8.0 million in lost productivity and cleanup costs (assume $60/bbl oil). This does not even factor in a possible $4,300 per bbl[41] fine that was recently imposed in an oil spill case for violation of the Clean Water Act (Gilbert, 2014). For a nominal 500 bbl tank at a hydro fracking battery, that amounts to $2.2 million in fines alone. So, the total loss for one lightning strike on a fracking battery can exceed $10 million dollars.

From a risk cost prospective, the annual financial exposure varies by location and age of wells involved. For our case study at Hatchett, the annual productivity risk cost exposure for just one direct lightning strike exceeds $1.6 million (accounting for lightning likelihood and 1 year old wells). Thus, any mitigation solution presented must have a smaller annualized cost basis per hydrocarbon tank to be considered.

Validation of my lightning mitigation system with IEC 61511 and IPL[42] principles for FGS[43] systems has shown that the annual residual risk cost is reduced to $50,000 per battery tank.

[40] Verification and Validation
[41] bbl is shorthand for barrel where one U.S. bbl of oil is 42 U.S. gallons.
[42] Independent Protection Layer (see Chapter 2)
[43] Fire and Gas System (or Solution; see Chapter 2)

Lightning striking a large hydrocarbon facility such as an oil refinery can have catastrophic consequences; in one such case, direct property losses totaled $56 million (2014 USD) with unpublished losses in productivity lasting years (Mahoney, 1997). Lightning is a fact of nature however, a direct strike can be mitigated, and as shown my solution will dramatically reduce risk cost exposure.

6.3 Validation of Assumptions, Appropriateness of Analysis Methodology, and Interpretation of Results.

It was assumed that real-time lightning sensor systems with associated strike mitigation were viable from a technical and cost basis. This assumption was validated though calculations for lightning risk cost, IEC 61511, and IPL performance calculations. It was further assumed that deployed atmospheric lightning sensors and tank charge sensors will serve as a critical component of the lightning mitigation IPLs. Sensors for atmospheric charge were validated through field deployments and subsequent performance to NAVSEA[44] and NOAA charge standards. Tank charge sensors showed some promise in field tests, yet lacked sufficient results to be validated with any standard level of performance or functionality.

Analysis methodologies leveraged for this research played a key role in answering our research questions. Calculations of geographically specific lightning threats highlighted the expected risk exposure with no mitigation. Deployment of both real-time lightning prediction sensors and charge tank sensors demonstrated a basis for a mitigation strategy.

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[44] Naval Sea Systems Command (NAVSEA)

6.4 Contributions to the Body of Knowledge

To date, there have been no scholarly research papers exploring the nexus of sensors for real-time detection of lightning threats for hydro fracking operations while considering fracked well productivity. Even more importantly, there has been no research showing how sensors can predict a near-time lightning threat and invoke low cost mitigative strategies in the event of a direct strike or discharge. Lightning is a persist threat to hydrocarbon storage tanks. Solutions were presented that if implemented, will save hydrocarbon storage and processing companies millions in loss avoidance from unmitigated lightning strikes.

The presented lightning detection and mitigation solution will have a direct impact on the risk cost profile of hydro fracking operations. I detailed a lightning mitigation solution based on sensors deployed to measure the lightning threat and charge buildup on operating hydro fracking battery tanks. This field research was performed at an operating hydro fracking battery of a multi-billion dollar fracking company. This research included the systems engineering of sensor systems for lightning threat detection and tank charge measurement.

Furthermore, the risk cost basis for lightning exposure at the Hatchett battery site was assessed and implications for risk were presented. A methodology was developed to calculate the lightning risk cost basis at any site in the United States. Moreover, this developed methodology can be used to asses lightning risk in hydro fracking operations at a given stage in the lifecycle of a well; this provides an important tool for planners.

A pathway toward extension of these solutions to a broader class of problems beyond hydro fracking operations has been prepared. Large hydrocarbon storage facilities such as Navy fuel depots and Liquid Natural Gas (LNG) terminals have reduced their lightning exposure through rigorous safety engineering and standards.[45] However, accidents form lightning strikes have occurred with catastrophic consequences (Mahoney, 1997; Chang and Lin, 2006). The methodology and technology developed in the course of this research will have a direct play in large-scale hydrocarbon storage facilities. Deployment of the researched solutions presented here, will have profoundly positive implications on the lightning cost risk curve at these large storage facilities.

Fig. 6-1. Large hydrocarbon storage facilities; Navy refueling and LNG terminals

The United States is still considering specifics Laws for LNG terminal exclusion zones and working to understand the consequences of leaks in relations to explosions or fires (Havens and Spicer, 2007). This uncertainty in regulation and disaster response makes these massive facilities particularly vulnerable to unmitigated lightning strikes.

Research Question 3 was presented in Chapter 2 as follows.

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[45] National Fire Protection Association (NFPA) 30 and others

3.) What are the broader implications for sensors and lightning detection beyond hydro fracking hydrocarbon storage?

Clearly, chapter 6 has shown the broader implications of solutions presented in Chapter 5. Section 6.4 discussed contributions to the body of knowledge and how these answers present solutions for large-scale hydrocarbon storage facilities. As an example a lightning strike on a large-scale hydrocarbon site resulted in $56 million in damages from infrastructure alone (Section 6.2).

6.5 Recommendations for Future Research

During the course of this dissertation research, I found technology areas that could potentially be used in future research investigations into this area. I recommend that any installation utilizing a system that includes the current Electric Field Monitor (CS110) system deployed at Hatchett should be interfaced with an IPL emulator. This will represent the beginning of the verification process and where software and hardware will be deployed and tested in accordance with IEC 61508 and ANSI/ISA S84. In particular, software and hardware will be designed with detailed operational realities at the core of development.

Lightning Mapping Array (LMA) technology can be used to assess the intensity and 3D attributes of electrical storms in real-time. The growth or decay of a storm can be assessed with this technology. Virtualized images with <50 m feature resolution are regenerated by leveraging natural VHF radio emissions from lightning discharges to render dynamic 4D[46] images (Goodman et al., 2005). The principal advantage of LMA technology is the ability to understand total lightning data and

---

[46] 3D with a time component

separate intra-cloud lightning from cloud-ground discharges. While the data is not presented anywhere near-real time – and therefore isn't immediately useful for a short occurrence warning it is anticipated that LMA research will result in systems that will help forecasters assess the metamorphosis of an electrical storm in real-time. By analyzing total lightning data, a 3-5 min warning can be provided before the first cloud-ground strike.[47]

Furthermore, I recommend that the petroleum industry should establish Public Private Partnerships (PPP) with curators of LMA systems including NOAA and NASA. By establishing these relationships, the petroleum industry can gain access to live LMA feeds for further study and eventual implementation for lightning mitigation (as described thought this dissertation). Furthermore, the government will gain valuable knowledge with potential applications for lightning mitigation at military explosive and ordnance storage facilities.

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[47] NASA, Short-term Prediction Research and Transition Center

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